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Cover Image: A view of BASF's 90,000-tpy acetylene plant at the Ludwigshafen Verbund site in Germany. Photo courtesy of BASF.

99TH ANNIVERSARY |1922–2021|

HP Industry Perspectives

HP Awards to stream October 28

On October 28, *Hydrocarbon Processing* will announce the winners of the 2021 *HP* Awards during a virtual streaming event. The 2021 *HP* Awards celebrate the innovative technologies and people that have been instrumental in improving facility operations over the past year. These benefits to the hydrocarbon processing industry are making operations safer, more efficient and more profitable. *Hydrocarbon Processing* wishes to recognize and celebrate the achievements these individuals and companies have brought to the global processing industries.

The 2021 *HP* Awards cover 20 strategic categories, including three people categories: Most Promising Engineer, Executive of the Year and Lifetime Achievement. More than 100 nominations were submitted from numerous countries around the world.

A list of award categories includes:

- Best AR/VR/AI Technology
- Best Asset Monitoring Technology
- Best Automation Technology
- Best Catalyst Technology
- Best Cybersecurity Program/Software
- Best Process-Plant Optimization Technology
- Best Digital Twin Technology
- Best Gas Processing/LNG Technology
- Best Health, Safety or Environmental Contribution
- Best Modeling Technology
- Best Instrument Technology
- Best Petrochemical Technology
- Best Refining Technology
- Sustainability Award
- Consulting Firm of the Year
- EPC of the Year
- Licensor of the Year
- Executive of the Year
- Most Promising Engineer
- Lifetime Achievement.

A complete list of nominees in each category, along with a description of each technology, can be found on pg. 57. The nominees are also listed on the *Hydrocarbon Processing* website: www.HydrocarbonProcessing.com/awards.

Hydrocarbon Processing will be streaming the announcement of the winners of each category during a special virtual broadcast, as well as live tweeting on *Hydrocarbon Processing's* Twitter account. The winners will also be posted to the *Hydrocarbon Processing* website on Friday, October 29 and will be featured in the publication's daily e-newsletter. The nominees and winners will also be announced in a special *HP* Awards section in the November issue of *Hydrocarbon Processing*.

For more information regarding the fifth annual *HP* Awards, visit www.HydrocarbonProcessing.com/awards. For more information on sponsorship opportunities, contact Melissa Smith, Events Director, at Melissa.Smith@GulfEnergyInfo.com. HP

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HP announces 2021 Top Projects award nominees

For the past several years, *Hydrocarbon Processing* has recognized the top refining and petrochemical projects of the year. These capital investments have significantly contributed to the expansion of the hydrocarbon processing industry and have been instrumental in providing new refined and petrochemical products to traditional and emerging markets.

Using Gulf Energy Information's Global Energy Infrastructure database, the editors of *Hydrocarbon Processing* have selected 11 nominees for the 2021 Top Projects awards. These capital investments can join a prestigious list of past winners. These winners include:

Refining:
- 2020: Visakh refinery modernization
- 2019: Kochi integrated refinery expansion project
- 2018: Jazan refinery
- 2017: KNPC's Al-Zour refinery
- 2016: KNPC's Clean Fuels Project

Petrochemicals:
- 2020: LIWA Plastics Industries complex
- 2019: Shell's Pennsylvania petrochemicals complex
- 2018: ZapSibNeftekhim (ZapSib-2) petrochemicals complex
- 2017: Petronas' Pengerang Integrated complex
- 2016: Dow Chemical's Oyster Creek PDH project

This year's nominees (**TABLES 1** and **2**) represent nearly $76 B in capital investments, more than 2.1 MMbpd of additional refining capacity and a significant amount of new petrochemicals production capacity—more than 5 MMtpy of ethylene capacity, 9.5 MMtpy of ethylene derivatives capacity and nearly 8 MMtpy of aromatics capacity.

Beginning October 1, readers can make their voices heard in an exclusive online poll at www.HydrocarbonProcessing.com. The winners will be revealed in *Hydrocarbon Processing's* December issue. HP

TABLE 1. Top refining project nominees

Operator	Project	Location
BAPCO	BAPCO Modernization Program	Bahrain
Dangote Industries Ltd.	Dangote oil refinery and petrochemicals integrated complex	Nigeria
Diamond Green Diesel	Norco renewable diesel plant expansion	U.S.
OQ8	Duqm integrated complex	Oman
Shenghong Petrochemical	Lianyungang refinery and petrochemicals integrated complex	China

TABLE 2. Top petrochemicals project nominees

Operator	Project	Location
Bayport Polymers	Ethane cracker and Bay 3 project	U.S.
Gulf Coast Growth Ventures	Ethane cracking and derivatives project	U.S.
Inter Pipeline	Heartland Petrochemicals project	Canada
Kazakhstan Petrochemical Industries	Kazakhstan integrated gas-to-chemicals complex	Kazakhstan
PetroChina	Jieyang refinery and petrochemicals integrated complex	China
Zhejiang Petrochemical Co.	Zhoushan Island integrated complex	China

INSIDE THIS ISSUE

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How to achieve industrial autonomy in the refining and petrochemical industries

Driven by advances in digitalization, the convergence of operations technology and information technology and the digital transformation of infrastructure and industry, process industries are gradually moving from automated to autonomous operations.

Within refineries and petrochemical complexes, the behavior of the material inside pipes and equipment is governed by five well-understood principles: conservation of mass, conservation of energy, conservation of momentum (fluid mechanics), thermodynamics (equilibrium operations) and chemical reaction (kinetics and catalysis). Each of these principles has been used by engineers for generations to design and operate plants safely and efficiently.

The tools used by engineers to undertake this work have evolved considerably over the years, from manual slide rules and calculators to mainframe computers and, finally, to purpose-built chemical engineering design and simulation applications.

Likewise, in operations, we can observe a historical and maturing technology set—from manual processes (Level 0) to fully autonomous operations (Level 5). These levels are used industry-wide to track the progression of operations (FIG. 1).

However, there are multiple domains of governance in large, complex process plants, ranging from the safety of people and the environment to quality, logistics and regulations. Each of these domains has its own set of decisions and challenges. A few of these will be examined in the following section.

Cross-domain linkages. The key to progressing performance is to look at cross-domain linkages and ultimately render these as intelligent, resilient and autonomous.

For example, walking around a plant, a noisy bearing in a rotating machine can attract attention, particularly if the machine is critical. Linking noise to equipment performance can help anticipate problems. Another example is an unexpected smell that hints that something needs attention.

Making such links across the control system can help drive more autonomous operations. Additional indicators—such as an interface level or water boot level—can be observed by fixed or mobile cameras, enabling operational decisions to be made based on the observations.

To this end, there are plenty of sensing methods to mimic sight, hearing and smelling via cameras, gas detection and acoustic sensors. Some of these sensors can be combined with sensors that feed directly to higher-level optimization.

Another example shows the linkages across functions. Switching crude oil feeds to a crude distillation unit remains an ongoing challenge at many sites (e.g., reducing disturbances to product qualities and minimizing operational action). A more autonomous approach would identify key inputs such as accurate or predicted crude tank contents—including any mixing or layering effects—and then link this information to unit controls. More broadly, a direct link from plant scheduling to the autonomous start/stop of a crude switch—to meet scheduling goals with little or no operator intervention—would be beneficial.

Defined procedures that cut across domains are key to achieving intelligent, resilient and autonomous operations. The primary goal is not eliminating human operators, rather it is deploying technology that allows those humans to make better decisions.

Control to optimization. In the refining and petrochemical sectors, progress has been made in recent years to improve plant outcomes in terms of safety, reliability and efficiency. The application of technology has played a key role in this effort.

Process control loops run in automatic mode, continuously correcting deviations in single process values. Alarms provide warning signs of where the process is at the current time, prompting operators to try to understand the nature and cause

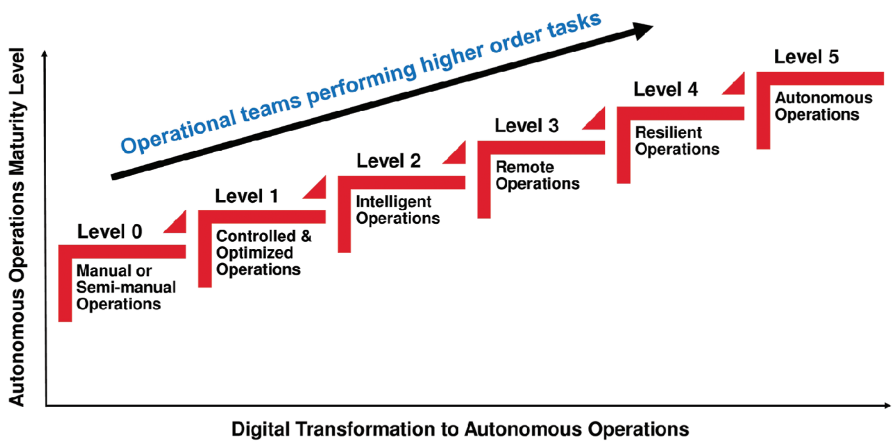


FIG. 1. The progression of operations.

of the incident and to mitigate unwanted effects. This has been the mainstay of process control since the days of pneumatic control and wall-filled panels of controllers and alarm lights.

The key to progressing performance is to look at cross-domain linkages and ultimately render these as intelligent, resilient and autonomous. Defined procedures that cut across domains are key to achieving intelligent, resilient and autonomous operations. The primary goal is deploying technology that allows those humans to make better decisions.

The progression of technology means that the scope of a single operator today is easily three times what it was before digital control systems. Combining multiple event occurrences by the control system into concluded conditions can help operators achieve more intelligent operations. Automated or semi-automated operational procedures also help guide operators, along with context-sensitive documentation.

Advanced process control (APC) is used to manage multiple interactions and control complex processes to reduce energy consumption while maximizing product yields. Industry is now benefitting from APC models that update themselves, even in closed-loop ones, with no interruption. This helps achieve the resilience of advanced controls.

The oil and gas industry also understands the importance of optimizing multiple units—particularly in refineries and petrochemical complexes where there are multiple processing options for different streams—to meet production goals or maximize the output of higher-value products.

Refineries and petrochemical complexes typically have run lengths of 3 yr–4 yr between major shutdowns. During that time, plant equipment (e.g., reactors or distillation towers) gradually fouls and/or degrades over time. Catalyst performance degrades, as well. This means that reaction severity, as expressed by temperature, must rise closer to metallurgy or refractory limits. Presently, this long-term cycle is managed manually, with multiple decision points.

However, much of this can be supported using simulation (e.g., using a digital twin) to achieve better performance over the run-length cycle of a plant. When linked to the overall economic optimization of a site, this enables the enforcement of run-length driven objectives, underscoring intelligent and resilient operations.

There is also optimization across multiple units in which the interaction is more economic than process-driven. Technologies to express this relationship of macro-level economics and micro-level stream flow targets are part of the latest developments, helping to make overall optimization more autonomous. A site-wide or refinery linear program model can be linked to individual controls through clever transformation of the decision space from one level to another. Therefore, the governance of plant economics can be made more autonomous.

Similarly, models that run dynamically can help instruct and train operators to understand the state of their unit and what actions may be required, enabling them to react in the best possible way. Again, this underscores resilient operations.

Lastly, for offsites operations, where there is remarkable linkage between feed logistics, process units, product blending in refineries and finished product logistics, more can be achieved by taking new approaches to tank farm valve management or the capture of measurements from the field. The use of wireless communications over a tank farm or marine loading dock can help achieve more intelligent logistics operations, enabling field devices to provide additional information. An operator may then be guided to the exact location for a needed manual operation.

Alarms and process safety. Alarm management and the analysis of alarm logs can help operators and engineers understand the nature of over-frequent events. There are also events captured automatically by safety instrumented systems. Safety event logs have been the subject of manual reviews, while alarm management has progressed in scope and breadth of supporting analytics. Enforcement of mode-based alarms has also expanded the scope of alarm management, but these remain same-unit mode indications. Cross-unit or transitional alarm settings are not generally implemented.

Process and functional safety have—for several years—had well-defined rules and governance principles, from hazard and operability study (HAZOP) and layers of protection analysis (LOPA) to defined safety integrity requirements. However, verification of function remains largely described in concept as part of standards such as IEC 61511. Achieving more closed-loop verification and flagging the need for remediation of safety elements, such as sensors, valves or logic, are also part of achieving more resilient operations. Whether the scheduling of valve and sensor verification or the notification of results, capturing such information and linking with the process control domain are part of an autonomous approach. Lastly, autonomously managing temporarily degraded safety loops can benefit a plant by removing the requirement for human intervention and ensuring consistent, safe operation.

Process and equipment asset health and performance. In recent times, the health and performance of equipment assets (e.g., pumps, heat exchangers, compressors and filters) have been undertaken using representation models of structure and behavior. For example, design and real-time performance data of a pump, including its pump curve, along with information on the motor driver and its characteristics, are used to model pump behavior. This has helped give rise to a templated model to benefit all instances of the same type of equipment. While the health and performance of individual equipment are better observed and flagged automatically to engineers for observation and maintenance (including the link to a maintenance system), this is still undertaken on single assets.

The industry has reached a point in engineering oversight where the next step is to benefit from cross-asset behavior flags. Does the temperature of incoming fluid from an upstream exchanger flag an event to the pump? Does a deficiency in

the pump achieving enough discharge head get flagged to a downstream reactor? Autonomous operations in engineering surveillance mean cross-asset conversations in which signals of health and performance are shared.

As described earlier, the performance of process and equipment degrades over the run length of a plant. The adaptation of performance criteria over that time can help achieve resilient operations within the scope of what is possible at any point in the run. Likewise, asset health and performance can benefit from better information on the activity surrounding them, including ambient temperature, pressure, gases detected in the area and any known process safety degradations.

Remote operations. In the scenarios described, operator actions in the field have reduced extensively. Within refineries and petrochemical complexes, operators should be focused on performance improvement rather than data collection and manual analysis. The achievement of control center locations away from the plant site is now more possible than ever before.

However, remoteness is also for project activities within a facility, as well as for new units, expansions or revamped units. The changes in infrastructure of control, safety, and security (including cybersecurity) can be achieved remotely, with minimal plant impact, up to point of cut-over. This is achieved by separating the design of control, safety and security infrastructure from physical equipment and using universal I/O technology that renders every control cabinet the same and every channel able to be configured for any input/output purpose.

With remote capabilities also comes the prospect of remote support for control and safety systems infrastructure. This can be achieved in a cyber-secure way, with the control and safety system assets doing the talking on the state of their health and performance.

Enabling systems infrastructure. In industrial process control, risk assessment methods identify where critical faults can occur with a high consequence, and personnel design and implement ways to verify that a single failure does not cause disruption.

Being resilient means failures can occur, but the system or operation continues to operate normally, and recovery is automated. If something fails, a redundant controller takes over the computing load.

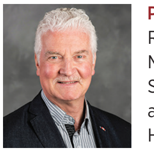
For example, the author's company allows multiple process controllers to operate as a distributed mesh—like a data center of controllers. This approach enables simpler project engineering because control strategies no longer need assignment to a specific physical controller. Instead, they can be deposited in a community of controllers that will automatically distribute control to wherever there is available compute across process controllers.

This contrasts with traditional redundancy in which a single fault triggers a backup failure, and a second fault causes an outage. With resilience, operation continues even with multiple faults, running until the computing is exhausted.

Simultaneously, resilience must be considered across the entire operation, ensuring that operations can continue in the face of equipment failures, power outages and weather events. An important lesson from current uncertain times is that the industry was not fully prepared for a common-cause issue that affected humans. Having backup control centers helps increase automation resilience.

Takeaway. This article has examined how intelligence, resilience and autonomy can be achieved across functional domains. As much as possible, the decision space or governance domain between functions should be linked to benefit operations. There are always new technology developments targeting more autonomous operations, and these also play a role in interactions with operational activities.

The gradual maturing of operations across multiple domains towards more intelligent, resilient and ultimately autonomous operations must remain an industry imperative. HP



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Update your pump and mechanical seal specifications

A professionally presented course in pump fundamentals caught our eye recently. The presenter's explanations of basic pump design and construction, operation and design fundamentals were flawless, and he used superior animations and illustrations. The latter would have been helpful in the now 38-yr-old *Improving Machinery Reliability,*[1] and several more recent books on pump reliability improvements.

However, we realized that even a relatively recent course in basic construction and design of centrifugal pumps can miss out on teaching the details of improvements or upgrades that are routinely requested by best-in-class user companies. Common sense tells us that unless pump repair or upgrade shops have acquired that knowledge, they cannot convey it to the reliability-focused user. This is why users need to consider putting upgrade measures into their repair specifications and give the repair or rebuild shop notice that the purchaser's clauses *X, Y* and *Z* are improvements for which the repair contractor or shop will be compensated, and that the pump's owner/operator will insist on a competent pump shop carrying out the specified upgrades.

Here, then, are some seal-related "hidden facts" that are known but seem to remain under-reported. Facilities that pursue reliability upgrades count these examples among the many lessons learned in the 1980s. They contributed to certain top user companies becoming known as best-in-class performers.

Cyclone separators. These funnel-shaped devices are rather ineffective in removing solid contaminants from mechanical seal flush fluids. It is generally known that cyclone separators will only remove particles with specific gravities greater than 2.7. They may do little to clean up small particles that cause abrasion or degrade O-rings. Closed-loop flush plans are much preferred by best-in-class companies.

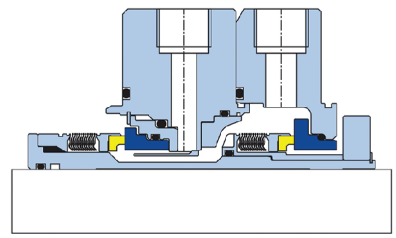

FIG. 1. Cartridge-style dual mechanical seal with bellows that may need to flex with every shaft revolution. Source: AESSEAL Inc.

Bearing housing protector seals. An article in the November 2020 issue of this publication explained why at least one large, multi-national petrochemical and refining corporation would not install bearing protector seal styles with radially outward-flung O-rings. That corporation's reliability professionals knew that such O-rings could seriously degrade if they contacted an opposing sharp-edged O-ring groove.

While the bearing protector seals at issue were an improvement over lip seals 40 yr ago, they no longer represent state-of-the-art products. Today, best-in-class companies will only use designs with axially or diagonally moving O-rings. The O-rings are located opposite large areas of contact. The latter designs were found highly reliable years ago, and References 2 and 3[2,3] contain much useful information on these and other upgrades.

Stationary vs. rotating face mechanical seals. Relatively few pump shafts deflect as much as the API-allowable 0.002 in. (0.05 mm), but shaft deflection does occur. If the mechanical seal depicted in **FIG. 1** is used, its spring-loaded rotating face will move back and forth once per shaft revolution. For a 3,600-rpm pump, that would be close to 2 B shaft revolutions per year.

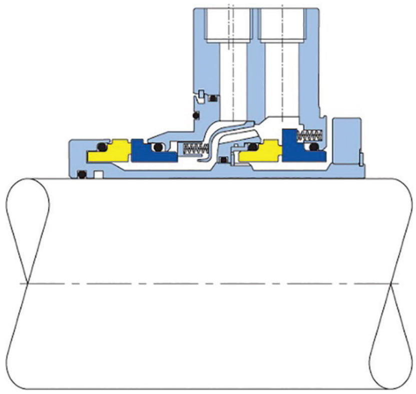

FIG. 2. Cartridge-style dual mechanical seal with bellows that may need to flex only once per pump start. Note the advantageous bi-directional tapered pumping impeller in this modern seal. Source: AESSEAL Inc.

In contrast, the flexing parts of the two mechanical seals in **FIG. 2,** albeit spring-loaded, are attached to the stationary housing bore or seal cavity. Upon starting the pump and with the pump shaft deflecting slightly, the spring-loaded stationary seal faces will accommodate the new situation. Half of their springs will be compressed by a small amount, and the other half will extend (stretch) by the same amount. No back-and-forth movement will occur.[2]

Water management seal systems. For businesses striving to achieve restorative and sustainable practices that harmonize with regulatory compliance, seal upgrading is a baseline requirement. Many reach the combined goals of not only saving water—a precious resource—but also capturing significant savings through maintenance cost avoidance. The cost-to-benefit ratio of seal upgrading must be assessed before moving in the dual-goal direction. Accordingly, competent business leaders make these assessments while also factoring in well-thought-out projections of changing demands and anticipated marketplace requirements. For some potential

users of highly successful water management systems, project implementation will prove challenging; however, competent seal manufacturers have data describing projects that resulted in high benefits in both competitive and sustainable returns. Many of these experienced seal providers will assist users in a variety of ways. Assistance can include well-supported benchmarking and highly detailed cost justifications. Experience shows that competent providers have facilitated maintaining the needed focus by submitting data on the merits of water management seals in large-scale beverage producing, paper manufacturing and mineral mining companies.

Again, pump users and purchasers will not obtain these betterments unless they spell out the needed improvements in a definitive inquiry and follow up with a legally binding purchase specification. Reliability-focused buyers may find it necessary to put repair shops on notice that waivers will not be issued, and that the job simply may not be awarded to them. The potential bidder will get the message if the entity issuing the inquiry specification stands firm. Needless to say: Pump users will not obtain different results if vendors continue to do in the future what they always did in the past. A user-purchaser who still accepts cyclone separators and, if avoidable, mechanical seals with spring-loaded rotary faces will have difficulty joining the ranks of best-in-class performers.[4] Regrettably, an indifferent owner-purchaser may keep the below-par supplier in the "business-as-usual business."

Recommendations. To summarize, becoming informed and specifying updated components whenever these exist will allow us to avoid suppliers that earn their living by catering to the uninformed and unconcerned. In contrast, pump users will reap sizeable dividends if they seek out and develop a mutually beneficial business relationship with above-average technical people. Above-average technical people do not merely voice opinions. They are well-informed readers who rely on well-informed tutors to bring them facts about best-available products. To bring you facts, the tutor must be a willing reader who steers clear of advocating practices that best-in-class companies have avoided for decades.

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Case 114: A local flooding event at a plant site

During a heavy rainstorm, flooding occurred at a plant location that had never before flooded. Concern arose that the underground storm sewer lines had become plugged with debris; however, it was undesirable to flush out the underground lines if it was not strictly necessary. Had the 6 in. of rain that had fallen in an hour (inches per hour, or iph) caused the flooding? The rain accumulation may have been too much for the storm sewer drains to handle. Typically, a heavy rain is 2 iph for the same time period. The question was: Were the drains plugged, or was the flooding due to the sudden high rainfall rate?

An analysis can help answer this question. **FIG. 1** shows a depressed basin-type area (A_{basin}) with the storm sewer drains (A_{drain}) that had flooded. The area (A_{rain} ft^2) is the rain shed that captures the rainfall and directs it to the drains. When the water height (h ft) in the basin (A_{basin}), which is a low point, reaches the height of the curb drain, the water starts to build up. The drains are gravity-type drains with a flow area of (A_{curb} ft^2), and there are (N) number in the basin area. The rainfall rate is (r ft/sec) over a period of time (t_{sec}).

With this information, an analytical model can be developed. The theory is much like filling a bathtub. When incoming water (meaning the faucet or rainfall from the watershed) is greater than the outgoing water (meaning the drain or storm sewers), the level (h ft) will build up in the basin (meaning tub) and eventually fill to a height (h ft) in (t_{sec}) seconds.

The water going into the basin can be calculated with Eq. 1:

$$Q_{in} = A_{rain} \times r \qquad (1)$$

The water out of the drains due to gravity can be calculated with Eq. 2:

$$Q_{out} = 0.8 \times N \times A_{drain} \times (2 \times g \times h)^{0.5} \qquad (2)$$

The difference is the amount stored, which builds up with time (t_{sec}), as shown in Eqs. 3 and 4:

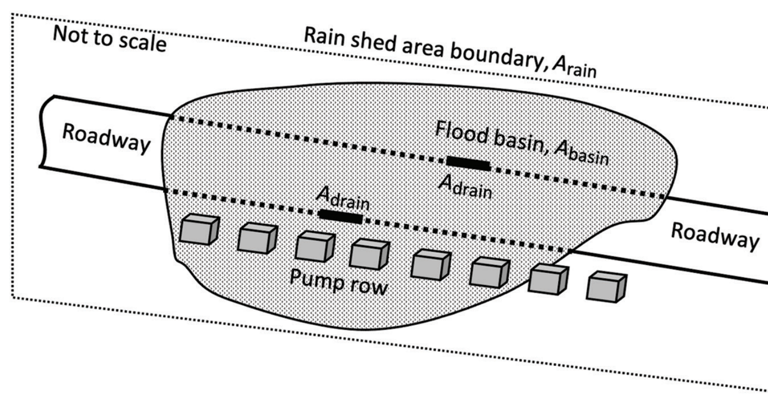

FIG. 1. Flooded basin area.

$$(Q_{in} - Q_{out}) = Q_{stored} = A_{basin} \times h \div t_{sec} \qquad (3)$$

$$A_{rain} \times r - 0.8 \times N \times A_{drain} \times (2 \times g \times h)^{0.5} = A_{basin} \times h \div t_{sec} \qquad (4)$$

This equation can be solved for (h) by iterative or closed form methods, as shown in Eq. 5:

$$\begin{aligned} &\text{During the storm, } N = 2,\\ &A_{curb} = 2\text{ ft}^2, A_{rain} = 320{,}000\text{ ft}^2,\\ &A_{basin} = 25{,}000\text{ ft}^2, r = 1.4 \times 10^{-4}\text{ ft/sec (6 in./hr)},\\ &g = 32.2\text{ ft/sec}^2, t_{sec} = 3{,}600\text{ sec} \end{aligned} \qquad (5)$$

TABLE 1 shows that the drains could not handle 6 iph of rain, and the level built up during the rainfall. A normal heavy rainfall of 2 iph does not appear to build up above the drain height. Some idea of whether the drains were plugged can be determined by noticing how long it takes for the basin to empty after the rain has stopped, as shown in Eqs. 6 and 7:

$$Q_{drain} = 0.8 \times N \times A_{drain} \times [2 \times g \times (h \div 2)]^{0.5} = 23.7\text{ cfs} \qquad (6)$$

$$(t)\text{ time to empty} = A_{basin} \times h \div Q_{drain} = 1{,}795\text{ sec or } 0.5\text{ hr} \qquad (7)$$

The site was dry again in less than 1 hr, meaning that it had drained at the proper capacity due to gravity alone. This suggests that the drains were acting as designed and probably were not plugged. It appears that the heavy hourly rainfall had caused the flooding.

TABLE 1. Flow model results

Condition	Flow entering, Q_{enter}	Flow leaving, Q_{leave}	Result, h ft
Heavy rain, 6 iph	44.4 cfs	32.5 cfs	1.6 ft buildup
Normal rainfall, 2 iph	14.8 cfs	12.8 cfs	0.3 ft buildup

This information was discussed with the plant facilities manager so that a plan could be developed for any future, sudden heavy rainfalls of this magnitude. The underground drain piping did not need to be flushed. HP

NOTE

Case 113 was published in *HP* July 2021. For past cases, please visit www.HydrocarbonProcessing.com.

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Protect safety valves using rupture discs

For many years, emissions were an unavoidable consequence of industrial development. An increased awareness of environmental issues and subsequent legislation are pressuring oil and gas companies to cut greenhouse gas emissions, and several have responded by setting reduction targets over the coming decades.

Operators have many options when pursuing emissions reductions. The focus here is the impact of various safety devices on this target. The first point of consideration should be the safety valves in use. Valves are an obvious place to start—no valve is 100% leak-tight, and their effectiveness decreases each time an activation occurs and the valve re-seats. Within the design and construction of a new plant, specifying a valve with a lower leak rate is a fairly simple solution. However, existing plants face substantial investments to replace older designs with newer technologies. In most cases, this is not a viable economical solution.

While there have been significant increases in their capabilities, safety valves are still not the ideal product when considering future net-zero targets (e.g., it is difficult to meet the exacting requirements of legislators). An alternative solution is needed.

Although rupture discs have been in use for many decades, they are often considered only as secondary relief when safety valve failure may occur. A lack of understanding persists among engineers in industry, and a number of myths surround the use of rupture discs.

Rupture discs. A rupture disc is a nonreclosing device and must be completely replaced after an activation. Nuisance downtime leads many operators to consider rupture discs as problematic; however, if a disc is rupturing frequently, a problem with the process is likely. Many operators still do not recognize that a disc performing correctly is the solution rather than the problem.

How can a rupture disc help improve safety valve performance? Rupture discs are 100% leak-tight, and installing a rupture disc in front of a safety valve provides double protection and helps meet emissions requirements. Leakage through the safety valve in normal operation is eliminated, and where overpressure activation exists, the valve re-seats to seal the process once the pressure is vented.

The belief that this arrangement increases project cost has been proven to be false. In fact, the opposite is true: a correctly engineered rupture disc will help lower operating costs and increase plant uptime.

In processes with a high concentration of corrosive media, increased temperatures and an operating pressure close to the safety valve set pressure, safety valves are pushed to their limits, resulting in poor performance, high maintenance costs to keep the valve as close to original specifications as possible, increased downtime for routine valve servicing and/or repairs, and higher manpower costs to cover the work scopes.

Solutions provided by some safety valve manufacturers include a higher specification valve, more exotic materials with higher CAPEX costs, and an increased cost of spares to maintain the valves. If a typical petrochemical plant with several hundred safety valves is considered, the CAPEX can be significant.

A rupture disc (**FIG. 1**) fitted upstream of the safety valve completely isolates and protects the valve from the process, reducing maintenance requirements. Reducing CAPEX costs is also possible by sourcing a rupture disc and holder in an exotic material, and a standard safety valve. The costs of a disc and holder are usually significantly lower than sourcing a high-specification safety valve that is compatible with the process media.

Protecting safety valves with rupture discs has become increasingly common

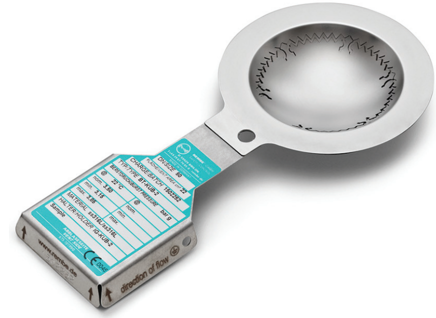

FIG. 1. A rupture disc for isolating safety valves.

in recent years across several industries. However, many operators fail to fully protect the safety valve by also isolating the valve from potential corrosion issues at the outlet of the valve.

In many cases, the valve outlet is not a separate discharge line, but is connected to other parts of the plant via a manifold that allows process gases/vapor to enter the outlet of the valve. If the process media can damage the valve via the inlet, this is also the case downstream.

A rupture disc can be used to isolate the safety valve outlet and prevent any contact with the process media. The rupture disc will also block any back pressure from entering the safety valve and remove those concerns during valve selection.

With burst sensors installed both upstream and downstream, rupture discs can be monitored and connected back to the control room for system reporting across the plant. Operators will know instantly which valves and discs are in a green or red state.

A myth surrounding rupture discs is that they can leak. Installing a disc as the primary safety device (i.e., without a safety valve behind it) can be a concern for operators looking to reduce emissions. The majority of leakages via rupture discs are caused by corrosion or damage during installation by mishandling or incorrect torquing.

FIG. 2. An ideal combination: a safety valve and rupture disc.

Rupture disc technology has improved significantly over the years to ensure that damages caused by corrosion or incorrect handling are all but eliminated. Modern rupture discs no longer use mechanical scoring techniques during manufacturing, which can lead to works hardening and corrosion over time. Advanced manufacturing technologies have resulted in robust rupture discs that are no longer sensitive to torque and virtually immune to damage during installation. Most spurious failures from rupture discs can be avoided by working with the disc manufacturer to select the ideal rupture disc for the process conditions.

During maintenance intervals individually imposed by operators, process safety rupture discs are dismantled, inspected and, if necessary, replaced by the relevant service and maintenance companies. To enable these companies to carry out these activities, seminars are available to train people on how to accurately use such specialized equipment. The assembly and dismantling of the rupture discs and corresponding burst tests show participants how complex the topic of rupture discs is and how sensitive the handling of these components should be. Selecting the right high-performance rupture disc and understanding its function is of the utmost importance for process plant operators. Specialized training can ensure that the installed discs are always in optimum condition and avoid any unnecessary unexpected downtime.

Overall, rupture discs can be used as a cost-effective and efficient way to create a leak-tight process and reduce emissions, whether on their own or in combination with a safety valve (**FIG. 2**). HP

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Hybrid modeling: Unlocking the value of data for oil industry assets

We live in a world increasingly driven by data scenarios for advanced analytics, predictive modeling and machine learning (ML), but how reliable is this for large oil and gas assets where safety and reliability are of paramount importance? Can the industry rely purely on machines to anticipate its needs, or does it need to stay with the more traditional physical modeling to determine safety, lifetime and maintenance of assets? The author believes the answer lies in a combination of the two.

There is no denying the value of data. Historically, there was not enough data to support ML algorithms, which improve with greater volumes of historical data.

However, the falling cost and size of electronics, distributed intelligence, easy connectivity and the Internet of Things (IoT) have contributed to an exponential rise in the amount of data available about assets and processes. Termed 'big data,' this opens the possibility of deeper insights into the performance of assets.

However, pieces of data on their own do not add value—this only comes with context and domain knowledge to enable the interpretation of data and extract value from it. If done correctly, the benefits can be huge, including reduced costs, optimized capacity and less downtime.

Artificial intelligence (AI) technology is only an enabler to handle data. However, it must offer and require business input and domain knowledge for an organization to harness the reward. In addition, it needs to be combined with cross-collaboration of data scientists and software engineers who can build a good, data-driven solution. Put these together correctly, and only the imagination limits the use cases for the oil and gas industry. For example, steps to increase the uptime and performance of an oil rig by detecting component fatigue and identifying areas of predictive maintenance could save companies millions of dollars a year.

How can safety be ensured? One of the challenges for heavy-asset industries is to manage safety-critical applications. How do you know you have the required data quality?

With the complexity of constantly changing assets and evolving processes, a pure data-driven model has difficulties in analyzing and predicting time series for safety-critical applications. It may also not include enough of the operating space to really understand the underlying physics, especially with the complexity of incorporating energy and mass conservation, or it may not have enough historical data to learn the insights needed. This could result in biased decisions, missed opportunities, outdated decisions, and, critically, put equipment, the environment and people at risk. This is where high-fidelity simulators using physical models can help.

High-fidelity simulators are tried and proven and, as they are based on first-principle physics, ensure system modeling in the full domain of operations. However, they are computationally expensive, making frequent predictions and real-time optimization difficult. Solving these physics-based models can also be complicated and time-consuming, and they may suffer from small differences between the plant and model as components wear or hidden parameters change.

The problem is that both pure data-driven models and high-fidelity simulators on their own have too much uncertainty to provide reliable, timely predictive and prescriptive analysis in safety-critical applications. The answer lies in a hybrid of the two.

Hybrid modeling: Unlocking the value of data. Although pure data-driven models and high-fidelity simulators of the physical world each have shortcomings alone, they complement each other perfectly. Data-driven models can learn statistical dependencies and process data a magnitude faster than simulators. Conversely, physical models offer robustness and transparency to ensure crucial, underlying factors are not missed.

Correctly engineered and with enough information from current operations, physics-based models and simulators can help the user understand complex processes and predict future events. This method is widely used and well-proven across multiple applications, including predicting the orbits of rockets or the behavior of nano-sized objects in modern electronics. ML algorithms are also designed to predict outcomes, which depend on the problem being addressed.

Fundamentally, there are two different scenarios for predictive modeling. In the first, there is a lot of experimental data on the behavior of the system but no direct theoretical knowledge. This makes it impossible to formulate a mathematical model of the system. Using ML algorithms, however, underlying patterns and correlations can be identified, and predictions made.

In the second predictive modeling scenario, the problem being addressed can be described using a physics-based model. This does not mean that a ML approach will not work. Using artificial neural networks designed to emulate the human brain and given enough examples of how the physical system behaves, the ML model will learn physics in the same way humans learn and, over time, it too will make accurate predictions.

By combining a physics-based model with ML in a hybrid modeling scheme, the best of both approaches is achieved. The result is a system that uses data-driven modeling, which is enhanced by the first-principal, physics-based models. This hybrid solution offers the robustness and quality of a high-fidelity simulator with the speed of response of a ML solution.

Enhancing data-driven models and physical simulators. Historical records can often lack the volume of data over sufficient periods to get robust predictions from ML algorithms. However, all potential operating scenarios can be created and taught to the data-driven model by simulating data.

Equally, data collected in real time and analyzed by the data-driven model can improve simulators to create a better match with reality and incorporate behavior outside the scope of the physical model. For example, perceptual quantizer curves can change slowly over time or experience a sudden step change if the well configuration on the other side of the pipeline changes. Models can be better matched to 'what if' scenarios using real-world data.

Advantages of hybrid modelling. Using a hybrid model offers several benefits. This approach means the modeled state is updated using real-time data, and data for the ML algorithm to ingest can be generated around typical operating conditions using the simulator. The ML algorithms offer the speed required to optimize the value of real-time data and can be used to optimize the system. Once the ML model makes a fast prediction, this can be checked in the simulator, and the solution fed back to the operator. The resulting solution offers the speed and versatility of a data-driven model and incorporates the transparency and physical constraints of the system provided by the simulator, providing verification and trust for safety-critical applications.

Takeaway. In a data-driven world, the value contained within is continually increasing and can offer tangible benefits to the oil and gas industry. The value of this data decreases over time, so a fast response will deliver greater advantages. However, this cannot be at the expense of safety, and modeling systems must provide transparency and robustness to ensure decisions are not biased and risks to people, assets and processes are not increased.

On their own, both pure data-driven models and physical simulators have shortcomings. However, a hybrid modeling-based solution offers an exciting new prospect to reap the benefits of both approaches to deliver an enhanced, reactive, robust modeling solution in safety-critical, heavy industrial applications. HP

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How HPI companies can protect against ransomware and other cyber threats

Ransomware has become an epidemic, and critical infrastructure is in the crosshairs. The Colonial Pipeline ransomware attack should be a wakeup call for every company in the hydrocarbon processing industry (HPI).

From 2019–2020, the number of ransomware attacks in North America increased by 158%.

Critical infrastructure organizations, especially those relying on Internet of Things (IoT) devices, are prime targets for hackers looking to cause the kind of massive disruption that incentivizes companies to quickly pay ransoms.

Ransomware data breaches and nation-state attacks, among others all pose a risk that industrial companies cannot afford to ignore. No matter where your cybersecurity practices stand presently, there are several actions companies can take to avoid becoming the next victim.

Implement zero trust. Start with a zero-trust policy. Assume every IoT device and everything else touching your network is unsecure. A zero-trust policy restricts the access these devices have to the rest of the network, granting access only based on business functionality.

Missing this step is one of the biggest mistakes companies make. Organizations often race to deploy new technologies and take shortcuts to speed up the process, assuming they will circle back later to lock down security. However, this rarely happens.

A zero-trust policy ensures that any unsecure devices or software cannot become a hacker's foothold into the rest of your network.

Segment and air gap your backups. Segment your network and implement controls to prevent the ransomware from spreading across your enterprise and limit the impact should it be hit with an attack.

Air gap your backups so they remain safe, even if ransomware starts spreading on your network. This will ensure a way to restore systems without paying the ransom.

Make sure you have the cybersecurity basics in place. Change the default login credentials on all devices. Use strong passwords. Keep up with firmware updates and software patches. Stay up-to-date on emerging threats and educate employees on them. Look up each device on your network to see if there are any known vulnerabilities and track any new ones that are discovered.

Lastly, make sure you encrypt all data, both at rest and in flight.

Add more advanced detection and protection. Implement intrusion prevention systems that actively block malicious traffic, and web application firewalls to add additional detection and protection at the application layer.

Log every event in your network, systems and storage, and use artificial intelligence and machine learning to examine the log data for suspicious activity and traffic patterns. These tools can alert you of any unusual activity that may indicate a security breach.

Prepare for the worst. Perform a business impact analysis to understand the implications a ransomware attack would have on your organization, including what it would cost, what functionality you would lose, how it would affect customers, etc. Then, refine and test your business continuity plan and incident response plan accordingly.

Make sure you have a disaster recovery (DR) plan that air gaps backups so you can restore all your data in an isolated bubble, perform forensic investigations and bring your environment back up in your DR environment.

Educate employees. Ongoing employee education on security practices can help avoid common cybersecurity mishaps and elevate the importance of security across your organization.

Train employees in various security protocols and have them sign off on information security policies annually. Ensure developers are building applications with cybersecurity in mind from the start and validate it before it goes into production.

The elevated importance of security. Ransomware attacks on industrial and critical infrastructure have only just begun. As ransomware continues to be lucrative and effective for hackers, the attacks will only continue to increase in number, severity and complexity.

Now is the time to review your security practices and take steps to ensure you do not become the next victim. HP

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Enhance aromatics production with concurrent reduction of environmental footprint—Part 1

Catalytic reforming processes produce olefin contaminants in aromatics streams via paraffin dehydrogenation side reactions. Operating catalytic reformers at higher severity results in higher yields of valuable aromatics, but it also results in higher olefins content in the reformate. Olefins must be removed from C_6–C_7 aromatics streams to meet benzene product specifications, and from C_8+ aromatics streams to meet specifications for paraxylene recovery processes.

Historically, olefins have been removed from aromatic streams in treaters using activated clay to promote the acid alkylation of olefins with aromatic molecules, thereby producing heavier compounds further separated by fractionation. While the process is very efficient, it inherently consumes valuable aromatics to remove undesirable olefins. The higher the olefins content, the higher the product loss. Given the current scale of paraxylene facilities, valuable product losses, even in small percentages, can have a massive impact on plant economics.

Selective hydrogenation converts olefins to paraffins and alkylaromatics via a reaction pathway that does not consume aromatics. As a result, aromatics yields are substantially increased, while the use of clay, which may account for up to 80% of the solid waste in a paraxylene complex, is dramatically reduced. This article presents key features and performances for the selective hydrogenation process, and options for its implementation in a plant block flow diagram. It also describes the benefits of selective hydrogenation addition to an existing facility. The benefits of selective hydrogenation integration in a grassroots facility will be addressed in a separate article.

Process background. The recent paraxylene capacity increase in China is adding pressure on existing aromatics complexes to improve overall efficiency to remain competitive. The very large scale of the plants coming onstream[1,2] means that even small losses in terms of percentage can have a huge economic impact on these new complexes. Optimized heat integration, reduced utilities consumption, improved selectivities and reduced investments are common themes for all processes at sites currently in operation, as well as for new aromatics facilities.

Since the adsorption process has grown into the industry workhorse for paraxylene separation, the removal of olefins contaminants from C_8+ aromatics streams has become a critical step, because even small olefins concentrations can adversely impact the recovery unit's capacity. Furthermore, product benzene has a very low specification on acid wash color, which is a measure of unsaturated impurities;[3] therefore, removal of olefins from C_6 aromatics streams is also a necessary step.

Reformed naphtha (or reformate) is the primary feed source for aromatic complexes.[4] In the naphtha reforming process, side dehydrogenation reactions of paraffins or paraffinic substituents, as shown in **FIG. 1,** can take place in addition to the desired naphthene dehydrogenation and paraffin dehydrocyclization reactions. Furthermore, the transition from high-pressure semi-regenerative reforming to low-pressure continuous catalytic reforming has resulted in a substantial increase of unsaturated species in reformate-derived streams.[5] The concentration of these contaminants is a function of reformer feed composition, the severity of the reforming operation and the catalyst used in the reforming process, among other elements.

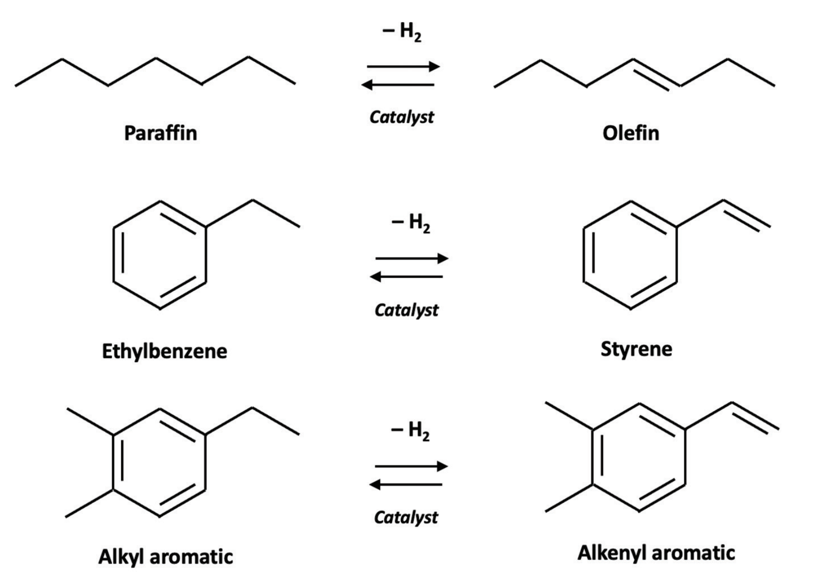

FIG. 1. Examples of dehydrogenation reactions producing olefins in a catalytic reforming unit.

Loss of aromatic product to remove olefinic contaminants. The bromine index (BI) is an indirect measure of olefins content in an aromatic stream.[6] For more than 50 yr, low BI has been achieved on C_6–C_7 aromatics and on heavy reformate by processing these streams through clay treaters. Two clay treaters per stream, operated in series or in parallel, are normally present. The acid sites of activated clays catalyze the alkylation of olefins with aromatic molecules. The heavy compounds resulting from this alkylation are then fractionated out, and the overall process is very efficient for olefins removal. Furthermore, significant improvements have been accomplished over the years, with increasingly active acidified clays and even zeolite-based catalysts proposed for clay replacement.[7]

Despite treater technology advances, the fundamental olefins alkylation chemistry remains the same and is illustrated in **FIG. 2.** Namely, one aromatic molecule is consumed per alkylated olefin molecule. In other words, some of the valuable aromatic product obtained at high cost via catalytic reforming is lost for the purpose of removing olefin contaminants. Moreover, reforming units in aromatic mode (i.e. maximizing aromatics output) usually operate at higher severity, which subsequently yields higher olefins content in the product. As producers increase operating severity to produce more aromatics, they also consume more aromatics to remove olefins.

Two main clay treating processes are present in typical aromatic complexes, one on the benzene-toluene extract stream and one on the heavy reformate stream. BI is usually lower in the benzene-toluene stream because most olefins in C_6–C_7 aromatics are removed through the extraction process prior to the separation of benzene from toluene. This is especially true when N-formylmorpholine is the solvent used in the extractive distillation process. The examples presented later in this article focus on BI removal from heavy reformate, meaning C_8+ aromatic streams.

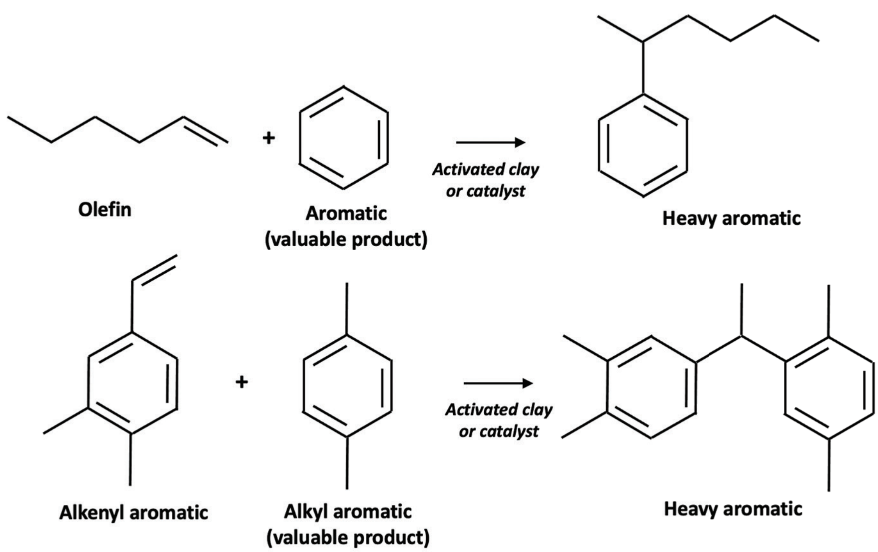

FIG. 2. Examples of reaction pathways of olefins alkylation with aromatics in clay treaters.

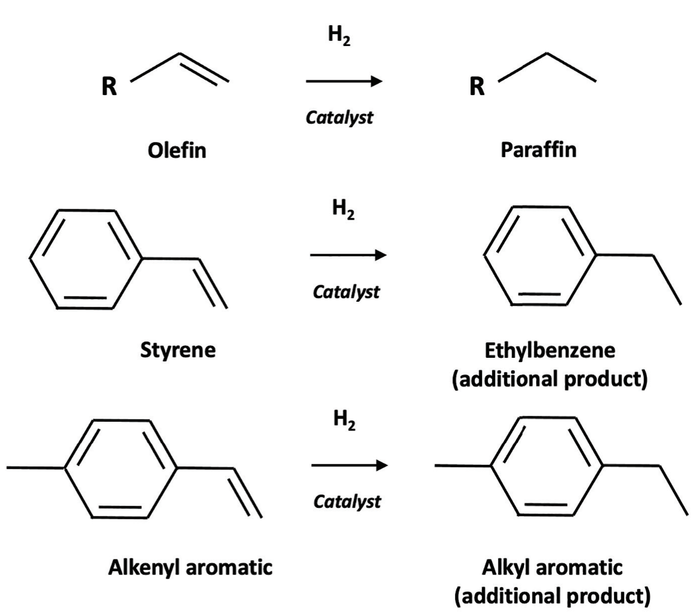

FIG. 3. Examples of selective hydrogenation reaction pathways for olefins removal.

Selective hydrogenation to avoid aromatic losses. Selective hydrogenation applied to olefins removal from aromatic streams is a simple, low-temperature process operated in an inexpensive vessel using a hydrogen (H_2) source—typically reformer H_2—and a catalyst. Depending on the unit location in a complex scheme, additional hardware may be required. The reaction pathways involved in selective hydrogenation are illustrated in **FIG. 3.** Two major benefits can be derived from a molecule management perspective:

1. Reaction pathways do not consume reformate aromatics; therefore, valuable product is no longer destroyed in the process of removing olefins.
2. When the olefin to be removed is an alkenyl aromatic, then hydrogenation produces additional valuable aromatics (e.g., the ethylbenzene in **FIG. 3** will be converted to benzene or xylene in a xylene loop). Based on heavy reformate compositions provided by aromatic sites for feasibility studies, alkenyl aromatics can account for more than 95% of the olefins to be removed in a C_8+ aromatics stream. This means that the benefit of selective hydrogenation vs. the clay treating process is essentially doubled by alkenyl aromatics conversion to high-value products.

In addition to the aforementioned aromatics production benefits, selective hydrogenation brings numerous advantages:

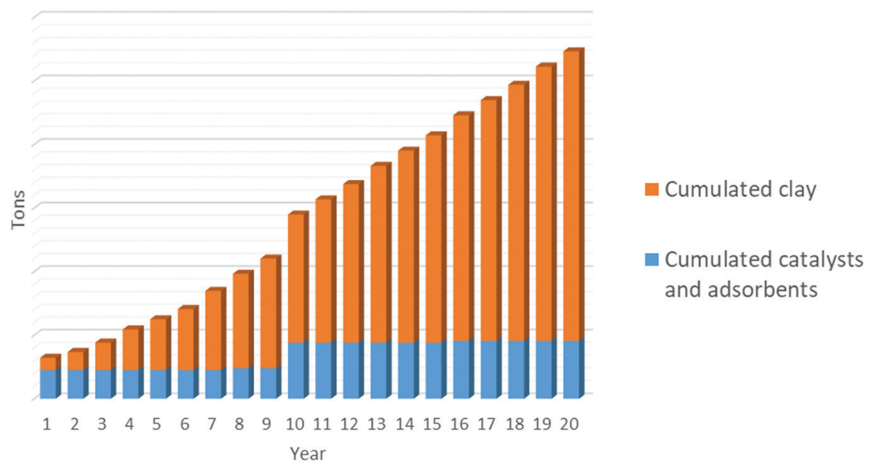

FIG. 4. Cumulated solids consumption in an aromatics complex.

1. Solid waste reduction: Clay treaters produce up to 80% of an aromatics complex's total solid waste. The massive environmental footprint of clay waste is illustrated in **FIG. 4,** showing solids consumption as a function of time in aromatics facilities. With selective hydrogenation, clay is essentially eliminated, meaning not only a huge reduction in solid waste generation but also significant savings in disposal costs.
2. Operating efficiency: Clay treaters are designed for a target cycle length at the start of aromatics production. With repeated complex debottlenecks via increased feed processing capacity and/or increased reformer severity, it is not unusual for treater cycle length to rapidly decline, forcing operators to unload/reload every 3 mos or even more frequently, with the following consequences:
   a. Clay start-of-cycle unavoidably produces high xylene losses,[8] for a period of 1 wk–2 wk, due to high initial clay activity. Xylenes are lost through transalkylation reactions involving two C_8 aromatics that produce a toluene and a C_9 aromatic. At sites replacing clay every 3 mos, this means 1 wk–2 wk every 12 wk at high xylene losses, with a severe economic impact:
      i. In complexes operating a transalkylation process, the impact is essentially energetic (fractionation, recirculation) because toluene and C_9 aromatics will be recombined in the transalkylation unit to produce xylenes.
      ii. In complexes that do not operate a transalkylation process, lost xylenes are irreversibly downgraded since toluene and C_9 aromatics are exported to the gasoline pool.
   b. Frequent clay change-outs constitute a significant operating (recurrent unloading and reloading events with potential safety concerns) and logistics (waste handling and disposal) burden, which is eliminated when clay cycles are exponentially extended.
   c. Short clay cycles resulting from complex debottlenecks make it difficult to maintain the low feed BI specification for the adsorption unit. The consequence is the potential permanent loss of a fraction of site recovery capacity during high feed BI excursions if clay cannot be replaced fast enough. With an upstream selective hydrogenation unit, this threat no longer exists.
   d. The transalkylation reactions catalyzed by initial high clay activity, as mentioned above, produce benzene when the C_8 aromatic involved in the reaction is ethylbenzene. Adsorption units have tight benzene specifications, and each clay start-of-cycle constitutes a potential exposure to off-specification feed for the adsorption unit.
   e. Selective hydrogenation upstream from an extraction process reduces extraction solvent consumption, as paraffins are easier to separate from aromatics than olefins.
   f. Selective hydrogenation reduces traffic in the heavy aromatics column bottoms, yielding energy savings.
   g. Pressure drop excursion events can occur in clay treaters and potentially disrupt production when heavy reformate dienes content is high, because dienes oligomerize over acidic catalysts,[9] leading to rapid coke deposition. Selective hydrogenation is very efficient at converting dienes, thereby eliminating this risk.

Selective hydrogenation process in the aromatics complex. The typical location of the two main clay treating processes in a modern aromatics complex is shown in yellow in **FIG. 5.** As previously explained, the benzene/toluene extract stream is clay treated to meet benzene product specifications, while the heavy reformate stream is clay treated to achieve separation process specifications on the xylene column overhead stream. In both cases, the heavy compounds resulting from olefins alkylation with aromatics are fractionated out via the toluene column bottoms in the case of the extract stream and via the xylene column bottoms in the case of the heavy reformate stream.

Using green dots, **FIG. 5** shows potential locations for a selective hydrogenation process in a modern aromatics complex:

1. **Reformer effluent upstream from the reformate splitter.** In this configuration, the selective hydrogenation process converts olefins for both C_6–C_7 aromatics and C_8+ aromatics streams. This arrangement results in the maximum conservation of valuable aromatic compounds and reduces energy consumption in the extraction unit, as well as in

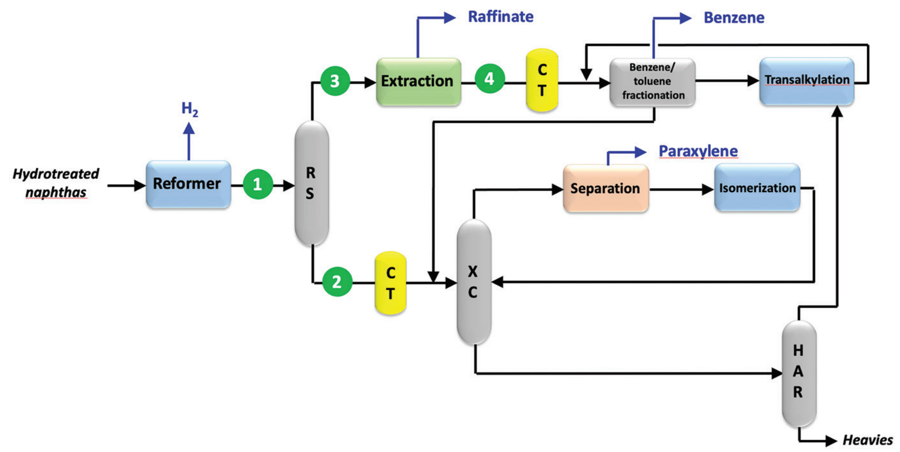

FIG. 5. Options for selective hydrogenation unit location in an aromatics complex.

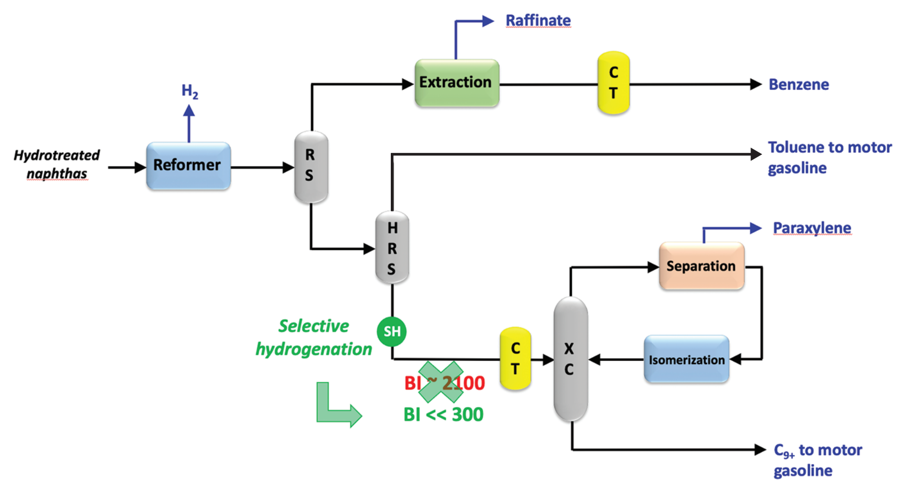

FIG. 6. Example 1: Complex producing parayxlene and benzene and exporting toluene to the gasoline pool.

the heavy aromatics column. This arrangement also corresponds to the largest possible feed quantity to be processed, which has implications with respect to the size of the selective hydrogenation unit.

2. **Reformate splitter bottoms.** This configuration offers the full benefit of valuable aromatics preservation for the heavy reformate stream, converts alkenyl aromatics to additional valuable aromatics, and significantly reduces the feed quantity, and therefore the size, of the selective hydrogenation unit. As mentioned earlier, the extraction process removes most of the olefinic co-boilers of benzene and toluene; therefore, maintaining low BI on light reformate is usually less challenging.

3. **Reformate splitter overhead.** Due to the higher solubility difference in extraction solvent between paraffins and aromatics vs. olefins and aromatics, paraffins separation from aromatics is easier in an extraction unit. Therefore, a selective hydrogenation process on the reformate splitter overhead results in lower energy and solvent consumption in the extraction process. The non-aromatic raffinate disposition scheme[10] is also essential. Depending on whether raffinate is fed to a steam cracker or to the refinery gasoline pool, it may or may not be advantageous to hydrogenate olefins prior to extraction.

4. **Benzene/toluene extract.** In this stream, BI removal is

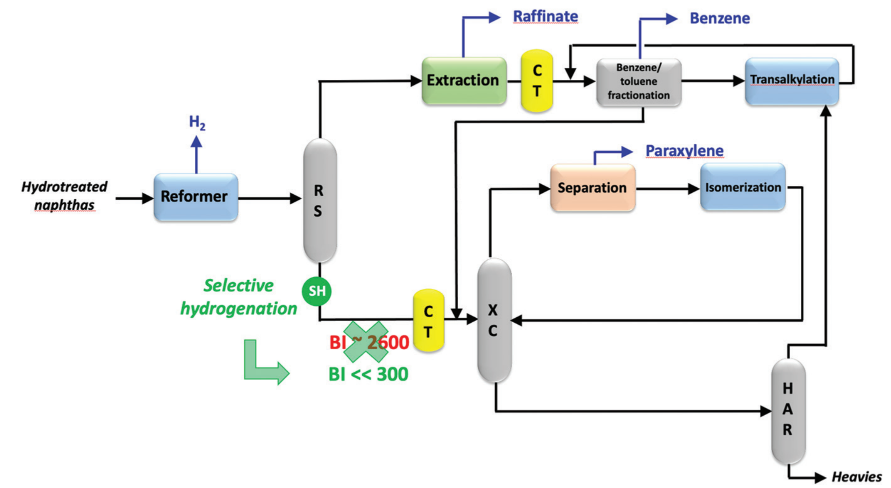

FIG. 7. Example 2: Complex producing parayxlene and benzene and maximizing aromatics production with a transalkylation process.

typically less challenging because most olefinic species would have been removed by the extraction process. However, specific site operating conditions or feed constraints may favor the addition of a selective hydrogenation process in this service.

Example 1. The first example considers a 700,000-tpy paraxylene complex producing benzene and exporting toluene to the gasoline pool. In **FIG. 6,** a commercial case for the potential addition of a selective hydrogenation unit is considered. The heavy reformate stream exhibits a BI of 2,100, which corresponds to approximately 1.05% olefins content.[11] Selective hydrogenation brings the following benefits:

- C_8 aromatics are no longer consumed to alkylate olefins in the heavy reformate stream. Xylenes are converted to paraxylene instead of being downgraded to motor gasoline. Similarly, ethylbenzene is converted to benzene instead of being downgraded to motor gasoline.
- Styrene (a fraction of the olefins to be removed) is hydrogenated to ethylbenzene and then converted to benzene instead of being downgraded to motor gasoline.

Economics are a function of the values associated with each stream at the site, the C_8+ aromatics stream specific composition and other proprietary information. Considering solely material balance improvement and disregarding all other benefits listed earlier, the complex achieves an approximate credit of $4 MM/yr on higher-value products by implementing a selective hydrogenation process on the heavy reformate stream.

Example 2. The second example considers a 700,000-tpy paraxylene complex producing benzene and maximizing aromatics production with transalkylation of toluene and C_9+ aromatics.

In **FIG. 7,** another commercial case for potential addition of a selective hydrogenation unit is considered. The heavy reformate stream exhibits a BI of 2,600, which corresponds to approximately 1.3% olefins content.[11] Selective hydrogenation brings several benefits:

- C_8 aromatics are no longer consumed to alkylate olefins in the heavy reformate stream. Xylenes are converted to paraxylene instead of being downgraded to fuel oil. Similarly, ethylbenzene is converted to benzene instead of being downgraded to fuel oil.
- C_9+ aromatics are no longer consumed to alkylate olefins. C_9+ aromatics are routed to transalkylation and converted to additional benzene and paraxylene.
- Styrene (a fraction of the olefins to be removed) is hydrogenated to ethylbenzene and then converted to benzene instead of being downgraded to fuel oil.
- Alkenyl aromatics are hydrogenated to alkylaromatics and routed to transalkylation for conversion to additional benzene and paraxylene.

Once again, economics are heavily dependent on values associated with each stream at the site, the C_8+ aromatics stream specific composition and other proprietary information. Considering only material balance improvement and disregarding additional benefits listed earlier, the complex achieves an approximate credit of $9 MM/yr on higher-value products by implementing a selective hydrogenation process on the heavy reformate stream.

Selective hydrogenation performance: Selectivity is key. High conversion is usually achievable at the appropriate set of conditions with a hydrogenation catalyst. With maximization of aromatics production being the primary incentive for commercial deployment, selectivity is the key parameter for selective hydrogenation to make economic sense.

In streams containing mostly aromatics, even minor hydrogenation side reactions leading to partial loss of aromatics are a huge obstacle. In the two examples listed, where selective hydrogenation respectively yields a credit of $4 MM/yr and $9 MM/yr from a material balance perspective, a few tenths of a percent of non-selective hydrogenation would suffice to erase all credits.

It is essential to hydrogenate olefins selectively—i.e., without loss of aromaticity. Since selectivity is first and foremost a function of the catalyst used in the process, adopting a catalyst with state-of-the-art selectivity is of paramount importance.

Recommendations. This assessment shows that the addition of an inexpensive process with pristine selectivity performance can result in substantial production credits and environmental footprint reduction that will last for the life of an aromatics complex. While no additional capital spending is often the easiest path in an existing facility, making no change is sometimes more costly than investing in incremental process improvement. Disregarding losses that are not monitored can be an expensive proposition in a highly competitive environment.

Other than the potential uses described here, selective hydrogenation has many applications in petrochemical complexes, including potential applications in aromatics facilities. One such application involves olefins removal from the effluent of a toluene methylation unit, which saves the cost of a fractionation step.[12]

As initially pointed out, product losses of a few percent can have a huge impact on the economics of mega-scale facilities, which is why selective hydrogenation is increasingly integrated into the design of grassroots complexes. The authors aim to address this subject in a separate article. HP

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CO_2 emissions reduction via a pinch study in a vacuum distillation unit

The project detailed here was carried out on a vacuum distillation unit (VDU) in the TÜPRAŞ İzmir refinery. Decreasing the carbon footprint of the facilities and being eco-friendly are some of the main strategies for TÜPRAŞ. Because the process is one of the largest units in the refinery, any energy improvement in the unit significantly affects the refinery's efficiency and carbon footprint. To determine the optimum energy efficient application, a pinch analysis of the unit was executed.

The refinery staff performed pinch studies with five different cases and also changed a number of shells for new heat exchangers in end of run (EOR) and start of run (SOR). Within a VDU, SOR and EOR mean the clean stage and dirty stage of heat exchangers in a turnaround cycle, respectively. The reasons for comparing two different cases in the project are that the VDU processes heavy products; therefore, fouling occurs in the heat exchangers between turnaround periods and the heat efficiency of the pre-heat train changes dramatically. Finally, 38 different scenarios were achieved for heat integration of the unit.

During the pinch study for each scenario, new operating conditions were determined and compliance with the temperature/pressure design criteria of the existing equipment were evaluated. In addition to the above evaluations, the most suitable scenario was selected by considering equipment costs and fuel consumption in all alternatives.

With the selected case, the project cost was reduced marginally because no new/additional heat exchangers were required. The fired heater duty was decreased approximately 4.6% for EOR and 2.4% for SOR conditions. This improvement is equivalent to ~1,700 tpy reduction of carbon dioxide (CO_2) emissions, which requires approximately 4,150 trees to offset.

The re-arrangement of the preheat train (or pinch study, in general) of process units via simulation tools promises huge potential. Such holistic solutions have been proven to decrease fuel consumption, EII index and CO_2 emissions for energy intensive industries.

Importance of the VDU. VDUs are among the largest units in refineries. The VDU separates atmospheric residue (AR) and contains valuable products that cannot be obtained in crude distillation units (CDUs) without high temperatures. Atmospheric columns may cause uncontrolled cracking after a certain temperature, which limits the maximum temperature. Uncontrolled cracking of hydrocarbons in distillation columns is undesirable, as this operation must occur only in well-designed reactors. Vacuum conditions lower the boiling point of hydrocarbons so valuable products in the atmospheric residue can be obtained by distillation without cracking. VDU products can be produced by diesel hydroprocessing (DHP) units, hydrocrackers, fluid catalytic cracking units (FCCUs) and a lube oil plant.

The VDU products mainly used in the lube oil plant (LOP) are spindle distillate, light distillate and heavy distillate. Additionally, the unit produces light vacuum gasoil (LVGO) and vacuum residue (VR). LVGO is sent to the diesel hydroprocessing unit and VR is sent to the propane deasphalting unit. Spindle distillate, light distillate and heavy distillate products are processed in the lube oil plant to produce spindle oil, light oil and heavy oil products.

The need for this study. Energy efficiency is always a hot topic in petrochemical plants and refineries—high-capacity production necessitates the search for energy reduction, so new technologies are implemented and potential improvements are always evaluated.

VDU energy consumption is immense, as is the unit's impact on a refinery's total energy requirements. Energy reduction projects are high priority, and it was considered that potential might exist to improve the authors' refinery's pre-

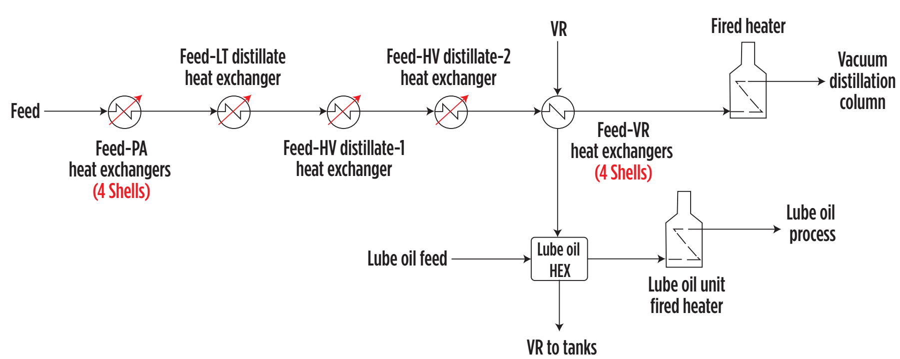

FIG. 1. Base model of the pre-heat train in a VDU and the heat integration between the VDU and the lube oil plant.

heat section. A preliminary version of the study with a commercial rigorous simulation model showed valuable improvement possibilities, so a pinch analysis in the unit was executed to determine the optimum energy efficient application for the pre-heat section.

VDU simulation and validation. A commercial rigorous simulation program was used to model the VDU with the goal of optimizing the heat exchanger network and the fired heater. The appropriate thermodynamic fluid package for this simulation was Peng Robinson. For characterization of the streams (AR, spindle, light and heavy distillate and VR), an oil manager was used. The unit model was configured by using field data (distillation, flowrates, operational data, etc.) and equipment process data sheets. The main focus was optimizing the heat network, which is why the rigorous models were considered for exchangers. For the analysis, the exchangers were modeled in both cases for SOR as clean and also for EOR as dirty. The main hydraulic and thermal checks were crucial steps in the study and were the main assumptions before validation.

VR from the VDU and LOP feed were integrated via a heat exchanger and the lube oil plant feed entered the fired heater after this heat exchanger, as shown in **FIG. 1.** Both fuel consumption effects for the VDU and the LOP fired heater should be considered before performing a heat integration study. The fired heaters efficiencies were assumed as 90% and 80%, based on the design for the VDU fired heater and lube oil unit fired heater, respectively.

For the first step of validation, the base model of the system was created. Heat and material balance were checked on the selected data set for this model. This model was then analyzed based on simulation outputs according to predetermined verification limits. In each step of validation, the exchangers design data were considered for detailed comparison with the datasheet values for duties, hydraulics and fouling factors. The acceptable criteria were ± 5% based on possible measurement errors and general refinery applications.

The base model. The base model of the system is shown in **FIG. 1.** The scope of this pinch analysis only covered the atmospheric straight-run fuel oil (ASRFO) heat network; the remaining sections of the unit were not modeled in this study. All alternative cases were based on the model discussed below.

CASE STUDY

Pinch studies were conducted for five different cases and the numbers of shells for new heat exchangers in EOR and SOR were changed. As previously stated, 38 dif-

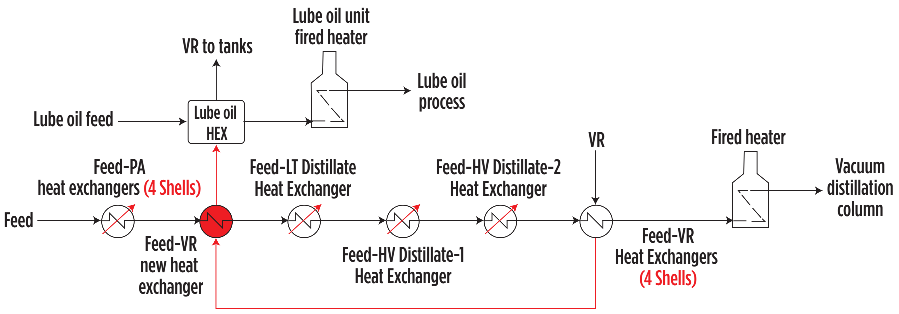

FIG. 2. Revised preheat train after Case 1.

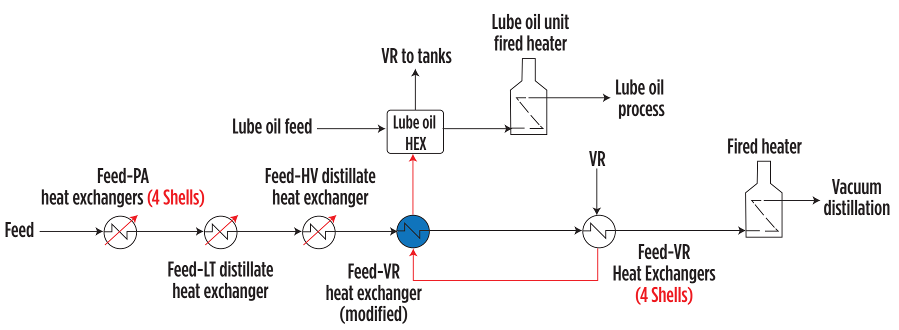

FIG. 3. Revised preheat train after Case 2.

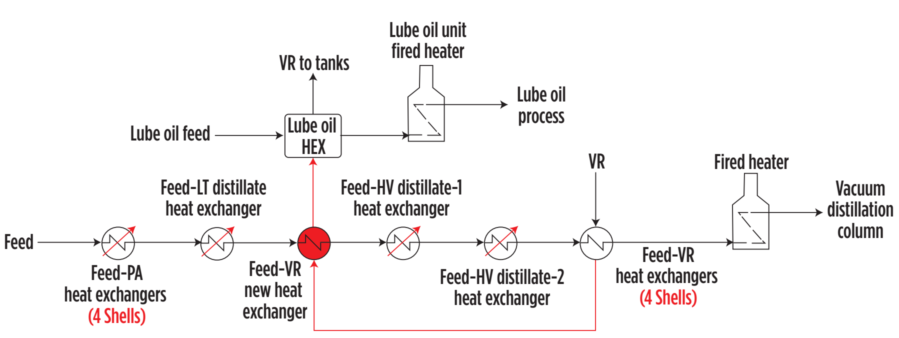

FIG. 4. Revised preheat train after Case 3.

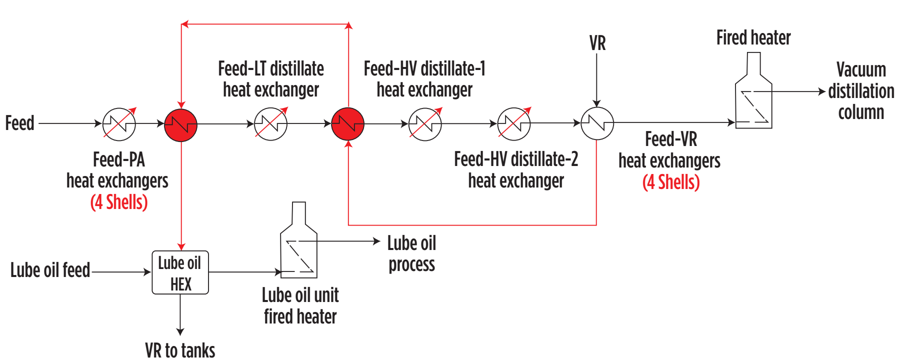

FIG. 5. Revised preheat train after Case 4.

ferent scenarios were achieved for heat integration of the unit.

Analysis of energy efficiency alternatives in the simulation model. After model validation, five different cases were generated to analyze fuel savings and CO_2 emissions reduction alternatives. Details of these alternatives are summarized here.

Case 1. In this case, the target was the addition of a new heat exchanger to the preheat train between the Feed-PA and the Feed-LT distillate for the heating charge of the unit via the VR stream, shown in FIG. 2. The number of shells in the new heat exchanger were changed to determine the effects on energy savings and CO_2 emissions reduction rates. The re-arrangement of the existing Feed-VR heat exchangers from four shells to 2 × 2 shells as an alternative scenario for the new system was also studied.

Case 2. In this case, the target was the rearrangement of the heat exchanger hot side services for the Feed-HV distillate-2 from the HV distillate stream to the VR stream, as shown in FIG. 3. All HV distillate streams were diverted to the Feed-HV distillate-1 heat exchanger—in this way, the Feed-HV distillate-2 heat exchanger is revised as the Feed-VR heat exchanger. The energy savings potential of the rearranged pre-heat train was studied to determine the effects on fuel consumption of the fired heater and CO_2 emissions reduction rates.

Case 3. In this case, the target was the addition of a new heat exchanger to the pre-heat train between the Feed-LT distillate and the Feed-HV distillate-1 for the heating charge of the unit via the VR stream, as shown in FIG. 4. The number of shells in the new heat exchanger were changed to determine the effects on energy savings and CO_2 emissions reduction rates. The rearrangement of the existing Feed-VR heat exchangers from four shells to 2 × 2 shells as an alternative scenario for the new system was also studied.

Case 4. In this case, the target was the addition of new heat exchangers to two separate locations for heating charge of the unit via the VR stream. The first addition is between the Feed-PA and the

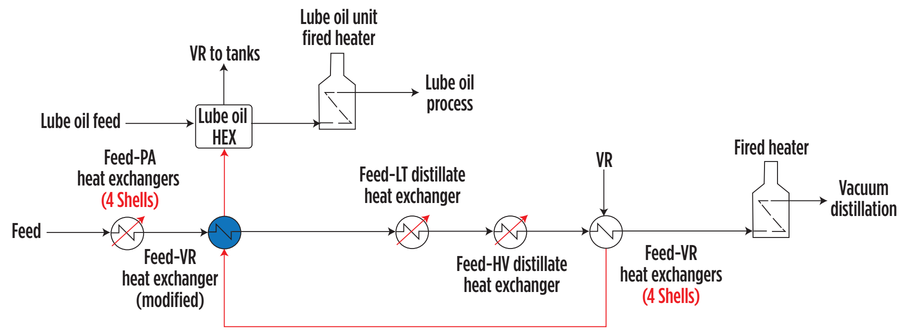

FIG. 6. Revised preheat train after Case 5.

Feed-LT distillate, and the second addition is between the Feed-LT distillate and Feed-HV distillate-1, as shown in **FIG. 5**. The number of shells in the new heat exchanger were changed to determine the effects on energy savings and CO_2 emissions reduction rates. The rearrangement of the existing Feed-VR heat exchangers from four shells to three shells was studied, and that one shell was used between the Feed-PA and the Feed-LT distillate or between the Feed-LT distillate and Feed-HV distillate-1 as alternative scenarios for the new system.

Case 5. In this case, the target was the rearrangement of the heat exchanger hot side services for the Feed-HV distillate-2 from the HV distillate stream to the VR stream, as well as the addition of the modified heat exchanger between the Feed-PA and Feed-LT distillate heat exchangers, as shown in **FIG. 6**. All HV distillate streams were diverted to the Feed-HV distillate-1 heat exchanger; in this way, the Feed-HV distillate-2 heat exchanger was revised as the Feed-VR heat exchanger. The energy savings potential of the rearranged pre-heat train was studied to determine the effects on the fuel consumption of the fired heater and CO_2 emissions reduction rates.

Checking equipment adequacy. Energy savings alternatives were analyzed through validated unit simulation models. In these analyses, the goal was to identify possible equipment that could create bottlenecks. The list of equipment adequacy controls included:

- Heat exchangers—Design temperature and design pressure controls were performed according to revamp operation conditions; and ρV^2 and vibration controls were also considered for all alternative scenarios.
- Pumps—Adequacy controls were performed on the rated capacity values in the datasheets of the pumps, and it was determined whether the pumps could meet the corresponding differential pressure.
- Fired heaters—Fuel savings and CO_2 reduction rates were analyzed for each case, and the effects of the cooled down VR stream on the lube oil plant unit fired heater were analyzed to determine if any bottleneck might occur.

Results. The VDU energy efficiency performance, fired heater fuel savings data and CO_2 emissions rates regarding the pinch analysis were checked for each alternative case. In the alternatives, SOR and EOR operation parameters and results were obtained from simulation models and the economic feasibility and/or CO_2 emissions reduction rates were calculated individually.

In Case 2 and Case 5, using the revised Feed-HV distillate heat exchanger as the Feed-VR heat exchanger proved an inadequate solution due to the hot side design pressure and hot side design temperature limitations, respectively. Accordingly, these two cases were eliminated from the pinch study results.

The rates of increase on both VDU, lube oil unit fired heater duties and fuel savings were tabulated in **TABLE 1** and **TABLE 2** for

TABLE 1. The effects of the pinch study on total fuel savings, simple payback periods and IRR values at SOR

Alternative scenarios		Total duty savings, %	Simple payback period, yr	IRR, %
Base Case [SOR]	-	-	-	-
Case 1	New heat exchanger addition / Shells in 1 x 1 (series*parallel)	3.98%	3.65	27.2%
	New heat exchanger addition / Shells in 2 x 1 (series*parallel)	5.91%	4.92	19.78%
	New heat exchanger addition / Shells in 3 x 1 (series*parallel)	7%	6.23	15.08%
	New heat exchanger addition / Shells in 4 x 1 (series*parallel)	7.59%	7.66	11.59%
	New heat exchanger addition / Shells in 2 x 2 (series*parallel)	5.82%	9.83	7.98%
	Modification of Feed-VR HEX / Shells in 2 x 1 (series*parallel)	1.88%	3.36	29.63%
Case 3	New heat exchanger addition / Shells in 1 x 1 (series*parallel)	3.94%	3.69	26.87%
	New heat exchanger addition / Shells in 2 x 1 (series*parallel)	5.94%	4.9	19.88%
	New heat exchanger addition / Shells in 3 x 1 (series*parallel)	7.06%	6.18	15.23%
	New heat exchanger addition / Shells in 4 x 1 (series*parallel)	7.66%	7.59	11.74%
	New heat exchanger addition / Shells in 2 x 2 (series*parallel)	6.25%	9.15	8.97%
	Modification of Feed-VR HEX / Shells in: 2x1 (series*parallel)	2.44%	2.59	38.55%
Case 4	Modification of Feed-VR HEX + New HEX addition / Shells in 1 x 1 (series*parallel) + 1 x 1 (series*parallel)	4.46%	3.25	30.62%
	New heat exchanger addition / Shells in 2 x 1 (series*parallel)	5.77%	5.03	19.29%
	New heat exchanger addition / Shells in 3 x 1 (series*parallel)	8.54%	5.1	19.01%
	New heat exchanger addition / Shells in 4 x 1 (series*parallel)	9.22%	6.29	14.9%

Case 1, Case 3 and Case 4 at SOR and EOR operating conditions, respectively.

Takeaway. The impetus for this project feasibility evaluation was achieving minimal CAPEX, a simple payback period with higher potential fuel savings, and a minimal impact on additional fuel consumption of the LOP fired heater. Accordingly, Case 3 (the modification of the Feed-VR HEX) was selected, as shown in **TABLE 1** and **TABLE 2.** The lowest project cost and optimum solution for site applications (construction works, equipment erection, etc.) were also attained.

Decreasing the carbon footprint of its facilities is one of the main TÜPRAŞ strategies. The pinch study showed that fuel savings of 4.6% for EOR and 2.4% for SOR conditions and a significant CO_2 emissions reduction of ~1,700 tpy were achieved. HP

TABLE 2. The effects of the pinch study on total fuel savings, simple payback periods and IRR values at EOR

Alternative scenarios		Total duty savings, %	Simple payback period, yr	IRR, %
Base Case [SOR]	-	-	-	-
Case 1	New heat exchanger addition Shells in 1 x 1 (series*parallel)	5.64%	2.32	42.98%
	New heat exchanger addition Shells in 2 x 1 (series*parallel)	8.32%	3.16	31.56%
	New heat exchanger addition Shells in 3 x 1 (series*parallel)	9.74%	4.05	24.4%
	New heat exchanger addition Shells in 4 x 1 (series*parallel)	10.59%	4.96	19.60%
	New heat exchanger addition Shells in 2 x 2 (series*parallel)	8.09%	6.38	14.64%
	Modification of Feed-VR HEX Shells in 2 x 1 (series*parallel)	3.62%	1.57	63.52%
Case 3	New heat exchanger addition Shells in 1 x 1 (series*parallel)	5.77%	2.27	43.95%
	New heat exchanger addition Shells in 2 x 1 (series*parallel)	8.61%	3.05	32.65%
	New heat exchanger addition Shells in 3 x 1 (series*parallel)	10.14%	3.88	25.47%
	New heat exchanger addition Shells in 4 x 1 (series*parallel)	11%	4.77	20.44%
	New heat exchanger addition Shells in 2 x 2 (series*parallel)	8.88%	5.81	16.38%
	Modification of Feed-VR HEX Shells in 2 x 1 (series*parallel)	4.55%	1.25	79.85%
Case 4	Modification of Feed-VR HEX + New heat exchanger addition Shells in 1 x 1 (series*parallel) + 1x1 (series*parallel)	4.99%	2.62	38.05%
	New heat exchanger addition Shells in 2 x 1 (series*parallel)	8.29%	3.16	31.53%
	New heat exchanger addition Shells in 3 x 1 (series*parallel)	11.51%	3.41	29.12%
	New heat exchanger addition Shells in 4 x 1 (series*parallel)	12.42%	4.22	23.34%

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Are furnace emissions proving to be your Achilles heel?

Furnaces, or fired heaters, provide the source of heat required for major industrial processes. As an energy-intensive industry, oil refining employs furnaces in most modern refinery process units. The prime source of heat in furnaces is fuel oil or fuel gas that is normally generated within the refinery; these are essentially anthropogenic sources of carbon. The carbon in these fuel sources ultimately ends up in the atmosphere in the form of carbon dioxide (CO_2), a major pollutant and recognized as a prime greenhouse gas (GHG).

The planet has been reeling with increasing global temperatures that are poised to create havoc if the present rate of temperature rise continues unabated. As per COP21 (Conference of Parties, Paris Agreement 2015), a concerted effort is being adopted to reduce carbon emissions to limit the global temperature rise within 2°C above pre-industrial levels—more specifically, targeting all efforts to limit the temperature rise within 1.5°C.

Without a doubt, the task is difficult considering the climate's antagonistic relationship with economic and financial parameters. However, carbon emissions reduction and carbon capture and sequestration (CCS) initiatives, as detailed in the Paris Agreement, are progressive steps toward sustainable and green development.

As part of this larger initiative, refinery furnaces have their own role to play. Furnaces are one of the largest polluters in terms of CO_2 emissions, and the rate of carbon emissions is directly proportional to the type of fuel being fired. Therefore, any reduction in rate of fuel fired is amplified multiple times into the reduction in CO_2 emissions. Considering that thousands of metric tons of CO_2 are emitted per year from a large-scale refinery, the emissions issue can become any refinery's Achilles heel in the decade to come as climate initiatives invariably gain momentum.

As the voices against carbon emissions grow louder, excellent progress is being made on this front with some valuable literature.[1,2,3,4] However, most of these documented studies focus on the reduction in carbon emissions on a pan-refinery level. Literature with respect to the impact of optimization at the grassroots level or equipment level is scarce. This article has been framed considering this, as well as the impact of carbon reduction strategies in quantitative terms on a furnace of appreciable heat duty. This work also explores the magnitude of carbon emissions reduction that can be achieved by common yet easy-to-implement strategies.

Furnaces and their tryst with emissions. Both basic sources of fossil fuels in fired heaters—fuel oil or fuel gas that is generated internally within the refinery—are rich sources of carbon and generate approximately 9,500 Kcal/kg–12,000 Kcal/kg (kilocalories/kilogram) of energy of the fuel burnt. However, each kg of fuel combusted generates approximately 18 kg–20 kg of flue gas: nearly 15%–20% of flue gas mass is CO_2. Effectively, each kg of fuel oil generates approximately 3 kg–3.5 kg of CO_2, whereas common refinery fuel gas generates approximately 2.5 kg–2.7 kg of CO_2.

While evaluating carbon reduction strategies for furnaces, it is imperative to review the strategies adopted on a pan-refinery level and then extend them to furnaces. It is unanimously agreed that the path to carbon reduction is defined by on the following three pillars:

- Efficiency improvements and process intensfication
- Fuel substitution and feedstock management
- Carbon capture, utilization and storage (CCUS), end-of-pipe solution.

Extending these three pillars to a refinery furnace, proven and time-tested techniques exist that can be covered under the first two categories (i.e., efficiency improvements and fuel substitution). However, the end-of-pipe solution of CCUS remains to be proven on a commercial scale.

While it is well-accepted that CCUS provides a significant reduction in carbon emissions, multiple factors stand as roadblocks between easy implementation on common refinery furnaces. For example, a standard crude refining facility consists of some 30–35 furnaces scattered across various points in the refinery—no "single point source" of emissions exists where CCUS can be planned, unlike power plant or fertilizer plant furnaces where CCUS is easier to implement. Moreover, the sulfurous content and the oxygen content of the flue gas are captured to act as a hindrance for the amine-based reagent that forms the heart of CCUS processes.

Even if these challenges are overcome, the utilization component in CCUS is a major chink in the armor for a refinery. Common utilization strategies include injecting CO_2 for enhanced oil recovery or for methanol generation, both of which are dependent on geographical proximity to the end user, as well as on prevailing markets for the end products.

It was decided to focus this study on the first two well-proven options: energy efficiency improvement and fuel substitution. CCUS has been kept beyond the scope of this article; however,

TABLE 1. Baseline data of a refinery furnace

Parameters	Values
Absorbed heat duty in furnace	23 MMKcal/hr
Total fuel flowrate	3,128 kg/hr
Oxygen level measured at arch	6 vol% (dry)
Fuel quality	Specific gravity of 1.01 (Type 6 fuel oil) C/H ratio of 8.196 Sulfur content of 0.5 wt% max
Flue gas temperature leaving the heater	400°C
Total flue gas load	1,512 metric tpd
CO_2 emitted	242 metric tpd

it is fervently hoped that the technology is soon demonstratively proven on commercial scale refinery furnaces, alleviating the inherent apprehensions.

The impact of the first two strategies has been examined for this case study on a moderate duty furnace commonly found in oil refineries. As it is proven that a reduction in emissions is intricately linked to fuel consumption rate—or, in other words, an increase in operational efficiency—effort has been made to enhance the furnace efficiency to its best achievable figures. The most common strategies include:

- Optimizing the current operation and plugging areas of inefficiency
- Retrofitting the furnace with an air preheat system to effectively utilize residual heat from outgoing flue gas
- Switching to fuel gas firing from existing fuel oil firing.

The first two steps exemplify efficiency improvement. Fuel substitution is demonstrated by the third step of fuel switchover, as well as an additional check case where fuel gas containing 60% hydrogen by volume has been investigated.

OPERATION ANALYSIS AND BASELINE DEFINITION

A Southeast Asian refiner was operating a furnace with the conditions detailed in **TABLE 1.** It was evident from the operating parameters that ample scope existed for improving performance. The refinery was facing an uphill task of curbing carbon emissions. Among many other furnaces in the refinery, the subject furnace was further investigated with respect to CO_2 emissions.

A deeper analysis indicated that the furnace was running at far from ideal operating conditions. For example, the furnace's fuel efficiency was a mere 75%, primarily due to the absence of air preheating or other heat recovery. In fact, the arch oxygen level of 6 vol% was quite high, which was a consequence of excess air being maintained at 38%. Therefore, it was evident the furnace presented ample opportunity to improve on operating parameters, which will also help in lowering the carbon emissions from its current level of 242 metric tpd.

The following steps emerged in pursuit of these strategies.

Step 1: Working on current operational lacuna—Excess air levels. Excess air levels impact the process from multiple directions. The higher excess air dilutes the flame zone with products that do not contribute to heat release, resulting in a lower heat source temperature and reducing heat transfer by radiation.

Secondly, higher excess air levels increase the mass of flue gas, increasing the sensible heat loss through flue gases. With more excess air, more heat is wasted in heating it from ambient temperature to the combustion temperature. Excess air leads to the burning of additional fuel, which is not desirable from an operational cost perspective nor from an emissions viewpoint. Accordingly, the excess air level was adjusted to 25% from the existing level of 38%; this 25% figure was in accordance with standard API guidelines, as well as common operating procedures for natural draft systems.

The results of this optimization exercise are shown in **TABLE 2.** It can be seen that excess air optimization—an essentially zero-investment solution—can lead to a carbon emissions reduction of ~8 metric tpd.

Step 2: Opting for an air preheat system. It was evident that continuing with the current natural draft system was insufficient for substantial cuts in emissions. Reducing fuel consumption was expected to impact emissions, so the installation of an air preheat system was evaluated in detail. Sometimes, fuel may be so inexpensive that the installation of an air preheat system may not be economically justified; however, emissions reduction will always justify higher heat recovery investments. Accordingly, an air preheat system was envisaged for the case studied here and appreciable carbon reductions were achieved. **Note:** The excess air level could be trimmed further to 20% with the use of air preheat systems in lieu of better control over the combustion medium.

Step 3: Exploring avenues for further reduction—Exercising the fuel gas firing option. After the evaluation of an air preheat system, it was decided to utilize a lower-carbon fuel source. Accordingly, refinery fuel gas was evaluated for furnace firing. It is vital to judge the overall refinery fuel balance before proceeding with this fuel shift. A sudden shift to fuel gas would have created a dearth in the fuel gas network, leaving the refinery with excess fuel oil. It is important to consider the use of this left-over fuel oil on a pan-refinery level for effective utilization. Common residue processing units, such as a delayed coker unit (DCU), can process this leftover fuel oil and generate valuable products. A study on fuel gas consumption was conducted and results are tabulated in **TABLE 2.**

Step 4: Tightening the noose—Fine-tuning fuel gas firing parameters. Having established a substantial reduction in CO_2 levels, it was time for the final fine-tuning. The inherently clean character of refinery fuel gas presented an opportunity to further enhance heat recovery by cooling the outgoing flue gas within 25°C of the acidic dew point. For refinery fuel gas with amine-treating facilities installed, the acid dew point is generally within 110°C–115°C with a level of 100 ppm hydrogen sulfide (H_2S). Further, better burning characteristics and ease of combustion also presented an opportunity to further optimize the excess air level to within 15%. The results of this exercise are shown in **TABLE 2**.

Check case: Hydrogen-rich fuel gas firing. Hydrogen (H_2) has been touted as the "energy of the future" and a promising solution to multiple persisting environmental and energy

TABLE 2. Comparative parameters after stepwise optimization

	Values			
Parameters	Step 1: Excess air optimization	Step 2: Air preheat system retrofit	Step 3: Switchover to fuel gas firing	Step 4: Optimizing fuel gas firing conditions
Absorbed heat duty in furnace	23 MMKcal/hr	23 MMKcal/hr	23 MMKcal/hr	23 MMKcal/hr
Total fuel flowrate	3,028 kg/hr	2,636 kg/hr	2,366 kg/hr	2,304 kg/hr
Oxygen level measured at arch	4.3 vol% (dry)	3.6 vol% (dry): 20% excess air	3 vol% (dry)	2.9 vol% (dry)
Fuel quality	Same as defined in **TABLE 1**		Fuel gas with following major component composition in mol%: H_2: 25%, N_2: 6.5%, CH_4: 36%, C_2H_6: 16%, C_2H_4: 11.8%; Others: balance	
Flue gas temperature leaving the convection section	390°C	370°C	363°C	360°C
Flue gas acid dew point	131°C	131°C	111°C	111°C
Flue gas temperature leaving the air preheater	390°C (no APH)	155°C	155°C	135°C
Total flue gas load	1,333 metric tpd	1,116 metric tpd	1,040 metric tpd	1,012 metric tpd
CO_2 emitted	234 metric tpd	204 metric tpd	144 metric tpd	140 metric tpd

TABLE 3. Check case: Hydrogen-rich fuel gas firing

Parameters	Values
Absorbed heat duty in furnace	23 MMKcal/hr
Total fuel flowrate	1,705 kg/hr
Oxygen level measured at arch	2.4 vol% (dry)
Fuel quality	H_2: 60 vol% CH_4: 40 vol%
Flue gas temperature leaving the heater convection section	~350°C
Flue gas temperature leaving the air preheater	135°C (assuming same exit temperature)
Total flue gas load	987 metric tpd
CO_2 emitted	95 metric tpd

TABLE 4. Critical performance parameters pre- and post-optimization

Parameters	Baseline condition	After Step 4
Radiant duty, MMKcal/hr	15.42	17.01
Convective heat duty, MMKCal/hr	7.52	5.94
Radiant heat flux, Kcal/hr.m^2	33,478	36,938
Maximum calculated tube metal temperature, °C	584	592
Maximum calculated film metal temperature, °C	514	515
Bridgewall temperature, °C	820	838
Ex-convection temperature, °C	400	360

security issues. It was determined that the study would be incomplete without evaluating the H_2-rich fuel gas firing case. For the sake of this study, fuel gas with a H_2 content of 60 vol% (and residual as methane content) was evaluated, considering that 60 vol% H_2 can be accommodated in an existing furnace with minor changes in hardware, although it is always recommended to thermally evaluate the furnace to match this situation. Results are shown in **TABLE 3.**

As evident, H_2-rich fuel gas firing shows remarkable results when evaluated for carbon emissions reductions. Firing 60 vol% H_2-rich fuel gas will reduce CO_2 emissions to < 40% of the baseline figure. However, practical limitations of refinery and commercial fuel pricing must be evaluated before this strategy can be adopted. Enriching the fuel gas composition by H_2 produced from fossil sources will not help the cause, as the overall CO_2 generated in a hydrogen generation unit (HGU) may be higher than the reduction achieved in this step.

Critical checkpoint: Evaluation of furnace performance parameters. As shown in **TABLES 1, 2** and **3,** the conversion of a natural draft furnace to a balanced draft furnace—and further shifting to fuel gas firing—appreciably reduces flue gas quantity and causes a major shift in the heat profile within the furnace. A lower flue gas quantity results in a lower convective heat transfer and, therefore, a higher radiant heat flux. A higher radiant heat flux leads to a higher metal temperature and film temperature in the radiant section. This must be evaluated well before such a conversion is attempted. A comparison of critical parameters is provided in **TABLE 4.** An analysis of these tabulated parameters was critical to ascertain the following points:

- Although the radiant flux increases as one moves to Step 4, the impact of these critical parameters can be absorbed within the case study furnace as sufficient design margins were already available.
- Tube metal temperature and film temperature are critical parameters that showed an increase. Although these can be managed within the existing design (of the studied furnace), in many cases, the increase in these parameters may force internal hardware modifications to operate the furnace within a safe envelope.
- An appreciable increase exists in the bridgewall or arch temperature, which can be managed within the existing design in lieu of inherent design margins and superior tube support metallurgy.

Further, the shift to fuel gas firing augmented with an air

preheat system required the following modifications and cross-checking:

- New burners suitable for forced-draft conditions
- New air preheater with ductwork—adequate plot space is required for such heat recovery systems
- New forced-draft fans and induced-draft fan must be installed
- Dampers and other blinding provisions required
- New control philosophy and complex control loop of the air preheat circuit.

Mission accomplished: Summarizing the study. With a primary focus on reducing carbon emissions from the furnace, the operating parameters and hardware change strategies were put to work. Results presented a strong sense of optimism with

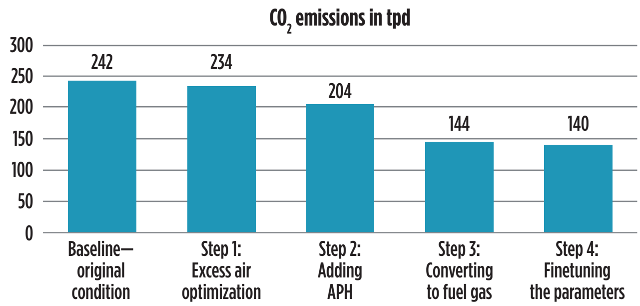

FIG. 1. Stepwise reduction in carbon footprint.

carbon emissions being reduced from 242 metric tpd to 140 metric tpd, which is a reduction of almost 43%. Refer to **FIG. 1** for the stepwise reduction in carbon footprint of the furnace.

Another positive and promising result is visible in the appreciable reduction in fuel consumption. Fossil fuels are depleting quickly and are costly sources of energy. A savings of the magnitude realized in this case study will result in significant monetary savings.

The examination of the case study furnace establishes, once again, the cardinal rule of carbon emissions reduction: enhancing operating efficiency. Although all furnace geometries are unique, some commonalities are applicable.

The study executed here also upholds that strategic decisions aimed at reducing the carbon footprint of a 23-MMKcal/hr furnace can curb CO_2 levels by approximately 100 metric tpd. Considering an average of 333 operating d/yr accounts for a carbon footprint reduction of 33,300 metric tpy. Considering carbon pricing—a common and well-debated buzzword—and assuming an average carbon price of \$20/t of CO_2, the revenue equivalent of more than \$6 MM/yr is generated. This alone outweighs the cost of an air preheat system, even in cases where the applicability of the air preheat system is not commercially justifiable by fuel savings, such as for small-duty furnaces.

Environmental pledge. Our planet has seen radical changes since the industrial revolution. Fossil fuels have dramatically improved the global quality of life; however, the positives are accompanied by an associated battery of negatives, the worst being industry's effects on the environment. With significant releases of GHGs, the planet's natural cycles have been altered (e.g., the depletion of polar permafrost, rising sea levels and increasingly frequent coastal storms, tornados, forest fires, floods and droughts). An organized, concerted effort is imperative throughout the entire value chain to reduce GHG emissions.

As detailed in this article, well-established solutions—efficiency improvements, waste heat integration, fuel substitution and H_2-rich fuel firing—were applied on a common refinery fired heater or furnace. The results are encouraging: significant carbon emissions can be reduced by existing, proven techniques that will pave the way for further advanced technologies. HP

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Diagnostics tools and techniques for large-scale operating fluidized beds

Intrusive and non-intrusive diagnostic tools and techniques for fluidized bed reactors are discussed here, with a focus on chemical synthesis catalytic reactions. These reactions occur in the gas phase and convert hydrocarbons to high value-added products using reactions with gaseous oxygen and possibly other reactants. Reactor operating conditions are typically limited to 500°C and 3 barg. Catalyst used is often Group A, in the 0 ɱ–200 ɱ (0 micron–200 micron) range, with > 20 wt% below 45 ɱ (fines). The diagnostic techniques presented here can be used for fluid bed systems of any size, but some methods may have temperature and pressure limitations.

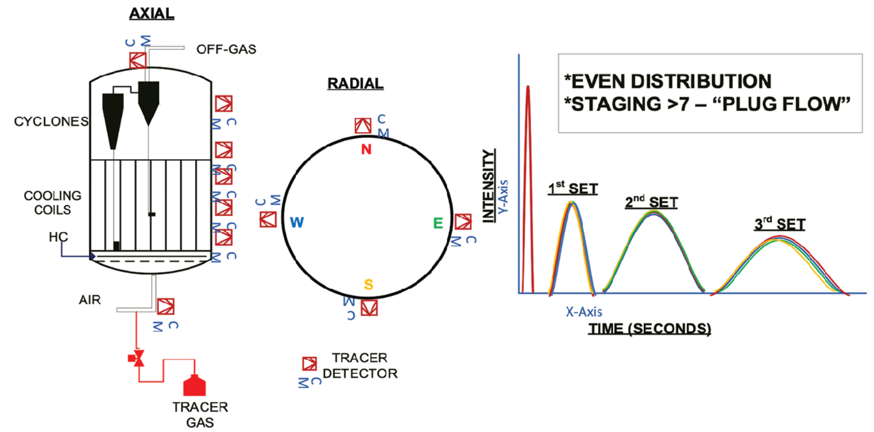


FIG. 1. Tracer test and results.

DIAGNOSTIC TECHNIQUES

A variety of tools and techniques are used to diagnose large-scale operating commercial fluid beds. They can provide a better understanding for improvement in current operations or identify the root causes of operational issues. Operational performance problems can be caused by errors associated with design, installation or equipment wear and failure. The diagnostic techniques are divided into non-intrusive techniques, which do not require a shutdown, and intrusive techniques, which do require a shutdown.

Non-intrusive techniques. These include the use of tracer gas and audio. The tracer gas method is typically performed by third-party companies that specialize in testing and data analysis.

The tracer gas test involves the placement of external detectors located radially and axially around the reactor. A pulse of the tracer gas is injected into the main gas flow stream (typically air) and its distribution within the reactor is recorded.

FIG. 1 shows the tracer test results on a very large (> 7 m) operating fluid bed reactor to determine the gas distribution and degree of mixing. The tests show the unit to be highly staged and, therefore, operating in plug flow. The result is typical of well-designed and well-maintained high fines Group A fluid bed reactors.

Audio is a simple, quick and low-cost method to "listen" to the fluid bed. Audio can be used to diagnose possible gas/solids distribution problems in high fines-content fluid bed reactors and is based upon bubble collapsing producing vibrations that are picked upon as sound waves. An external probe is moved around the bed diameter listening to sound at various locations, both radial and axial. The listening device can be one's ear (qualitative), sound meter (quantitative) or digital recorder with external microphone (quantitative, with digital files). The sound files can be downloaded into a computer for a comparison of intensive and sound analyses and filed for later comparison as a function of time.

Sound intensity is defined as the power per unit area carried by a wave. Power is the rate at which energy is transferred by the wave. In equation form, intensity (I) = P/A, where P is the power through an area A. The Si unit for I is W/m^2 (watts per meter squared). Sound intensity levels are quoted in decibels (dB) more often than in W/m^2. Our human ears perceive sound more accurately by the logarithm of intensity rather than directly to the intensity. The sound intensity level B in decibels of a sound having intensity I in the watts per meter is defined as Eq. 1:

$$B\ (\text{dB}) = 10\log_{10}\ (I\ /\ I_0) \tag{1}$$

where,

$I_0 = 10^{-12}$ W/m^2 is a reference intensity (threshold of hearing at 1,000 Hz).

Intrusive techniques. Intrusive techniques include the use of a movable probe and fixed-point detectors. A movable probe assembly includes an inert safety box connected to a nozzle on the reactor by a suitable sized full-port ball valve. The probe is pushed into the reactor through the safety box and the valve and can be moved laterally. The extent of movement

depends on the design of the probe and the presence of internals.

The probe tip may be a thermocouple for thermal profiling or a sintered metal filter for gas sampling or pressure recording. The thermocouple and pressure readings are data logged for transfer to a computer for analyses. A pre-pressured gas sample cylinder, with inlet and outlet valves, is filled with inert gas to very high pressure and attached to the filter outlet valve. The higher cylinder pressure is used to clean the probe sample line and filter. The sample cylinder is completely de-pressurized and reopened to take fluid bed gas and later analysed in the laboratory. The movable probe is re-positioned to obtain radial profiles. This technique may require a short fluid bed shutdown to mount the equipment on reactor nozzles.

The fixed-point detectors will require a shutdown for installation of stationary thermocouples or sintered metal filters at various locations of interest inside the fluid bed. Fixed-point detectors can provide temperature, gas analysis and bed density measurements. Density is obtained using two paired pressure probes aligned axially at suitable separation.

Commercial reactor diagnostic result. A large-scale fluid bed operating < 500°C and < 3 barg was analyzed using audio, a movable probe and fixed-point detectors. The overall reaction was (Eq. 2):

$$\text{HYDRCARBON} + \text{O} = \text{PRODUCT} + \text{CO} + \text{CO}_2 \quad (2)$$

FIG. 2 provides the results of both audio and movable probe analyses. The audio data was qualitative and indicated the loudest sound was in the northeast quadrant. The movable probe data showed no change in the temperature and chemistry [carbon monoxide/carbon dioxide (CO/CO_2) ratio] within the southwest quadrant of the reactor sampled.

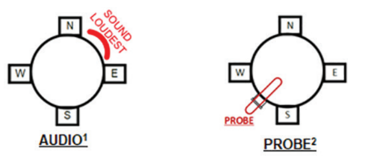
Several fixed-point thermocouples and aligned paired sample filters were installed at the same elevation during a major shutdown. After steady-state operation, the radial thermal profile was mapped, as shown in **FIG. 3.** The radial temperature profile indicated higher temperatures in the northeast quadrant area where the audio sound was the loudest.

The aligned, paired sample filters were also used for composition, delta pressure reading and bed density calculations. The results are shown in **FIG. 4.**

The lower CO/CO_2 and lower bed density were in the northeast quadrant, which is consistent with audio and temperature profiles. A simple test was conducted to measure the effects of probe tube length and tubing material of construction on gas sample results. Two different materials were used with three different lengths inside the fluid bed. The sample filters were tightly packed in a 15-cm circle located in the southeast quadrant. The results are shown in **FIG. 5.**

The length and material of tubing had no effect on sample tubing time exposure. Since the reaction CO/CO_2 is expressed as a fraction of the fluid bed exit gas CO/CO_2 ratio, it was concluded that the sintered metal filter was also not changing the sample composition.

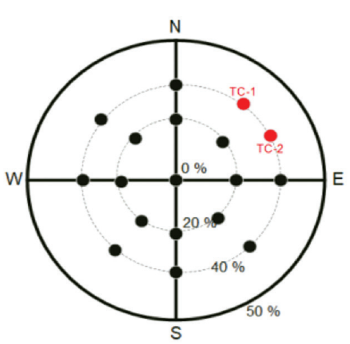
Takeaway. All techniques used yielded the same conclusion. HP



Probe data set[2]

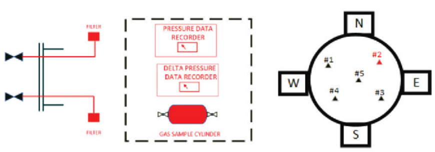
Probe, % of diameter	Temp, delta degree of bed avg	CO/CO_2, fraction of exit
10%	+1	1
25%	–1	0.97
40%	+1	1.02

FIG. 2. Audio and movable probe data.



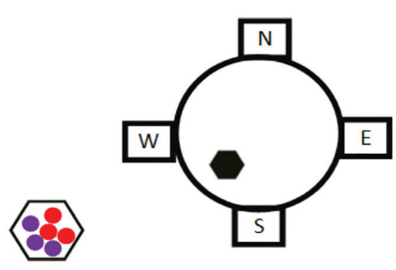
Item	Temp (+/–)
Center	–1 to +1
20%	–1 to +1
40%	–1 to +1
TC-1	+2 to +8
TC-2	+1 to +6

FIG. 3. Temperature radial profiles.



Position, #	Reaction CO/CO_2, fraction of exit	Bed density, % mean value
#1	0.98	103.1
#2	0.78	68.6
#3	0.97	100
#4	0.97	96.9
#5	1.02	109.4

FIG. 4. Gas samples and bed densities.



Material	Length, meters	Reaction CO/CO_2, fraction of exit
#1	0.6	1
#1	1.5	0.98
#1	3	1.02
#2	0.6	1.02
#2	1.5	0.97
#2	3	1.02

FIG. 5. Chemistry test on tubing material and length.

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Rigorous modeling of CO_2 absorbers using potassium carbonate solutions

As part of the global campaign to reduce CO_2 emissions, carbon capture and reduction are receiving increased attention from a variety of process industries, especially power generation and oil and gas exploration and production. One way to capture carbon is to remove the CO_2 from flue gas resulting from the combustion of fossil fuels. The hot potassium carbonate (HPC) process is one of the major commercialized processes for CO_2 removal. Potassium carbonate has been used as the absorption solvent to remove CO_2 from flue gas for more than 70 yr. At present, there are two commercialized technologies for CO_2 removal with HPC aqueous solutions: the Benfield and CATACARB processes.

The Benfield process, which was introduced by Benson, Field *et al.* in the 1950s, uses hot carbonate solutions as the chemical solvent to capture CO_2. The process employs high-pressure absorption and low-pressure desorption. The technology was licensed by UOP as the Benfield Process, with over 700 units in commercial service to date.[1] A typical application of the Benfield Process is CO_2 removal in the steam methane reforming (SMR) process for H_2 production.

Meanwhile, Eickmeyer and Associates Inc. have commercialized CATACARB, an enhanced HPC system for ammonia and H_2 plant applications since the early 1960s. The CATACARB process has been designed for more than 150 plants in over 30 countries, and for a wide range of applications, with the most common being ammonia, H_2, natural gas and ethylene oxide plants.[1]

With the advances in process simulations, rate-based column modeling has become more accessible and has potential applications in column design optimization and operation guidance. The rate-based, rigorous modeling is frequently used in gas absorption processes, in contrast to conventional equilibrium modeling. One company has offered the rate-based column model framework for CO_2 capture by K_2CO_3 or AMP in its proprietary software[a] since 2008.[2,3]

Borhani *et al.*[4] utilized the rate-based model in this software[a] to simulate the diethanolamine (DEA)-promoted HPC process. An acceptable agreement was found between model predictions and the industry-measured data. The rigorous model was further used to predict the optimum operation points where the absorber performs best.

Solos *et al.*[5] demonstrated that rate-based absorption modeling is a powerful tool for simulating and designing chlorine drying columns using sulfuric acid, as it can provide fundamental insight for the effect of equipment variables.

Mathias and Gilmartin[6] studied the effect of chemical equilibrium and reaction kinetics on the rate-based model performance of the CO_2 capture process with uncertainty analysis, using perturbation theory. They demonstrated that the rate-based model performance can be quantitively analyzed, thereby generating a reliable method for model validations. Utilizing a rate-based rigorous model not only can provide more cost-effective design with more accurate estimation of column performance, but also can offer opportunities to optimize column operation.

This article performs rate-based, rigorous modeling using a feature[b] of the previously discussed proprietary modeling software[a] via detailed kinetic models. The mass transfer correlations for packings available in the simulator are evaluated with model performance and compared with available industry data. The best-detailed and most rigorous model parameter set is selected and used for model predictions and optimizations.

HPC absorption process. The HPC absorption process includes two major columns: the absorber and the regenerator. The process flow scheme is illustrated in **FIG. 1.**

Both columns operate at similar temperatures (around 100°C). Absorption occurs at higher pressure (10 bar–50 bar), and CO_2 is desorbed in the regenerator at 1 bar–2 bar. Compared to amine solutions, the K_2CO_3 solution (typical 15%–40%

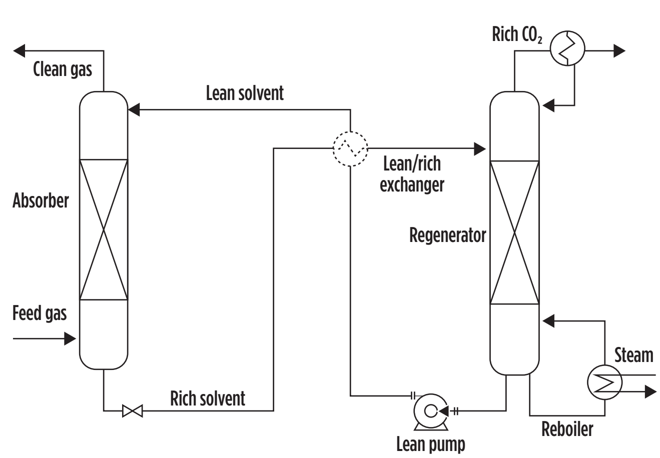

FIG. 1. CO_2 removal with hot potassium carbonate system.

K_2CO_3) is a weak solvent, which means that it is easy to desorb CO_2, although absorption is a challenge. The reactions in the regenerator are considered at chemical equilibrium with mass-transfer limitations, while absorption in the absorber is considered to be a rate-controlled process, which governs the overall performance of the system. The low absorption rate of the K_2CO_3 solution requires larger equipment areas to meet the design target, resulting in higher capital costs. To overcome the low absorption rate, promoters are added to increase the reaction rate.

Eickmeyer[7] showed that with the addition of 5%–10% catalysts or promoters, the solution activity of K_2CO_3 is enhanced by a factor of 2–4, and this has been demonstrated in commercial operations. Various promoters, including many amines, have been studied since the HPC process was first commercialized. Ayittey *et al.*[8] studied the boric acid-promoted HPC process using the rate-based simulation model. They validated their model with literature data and showed that with up to a 6% addition of boric acid, the CO_2 capture efficiency can be increased by 1.2%.

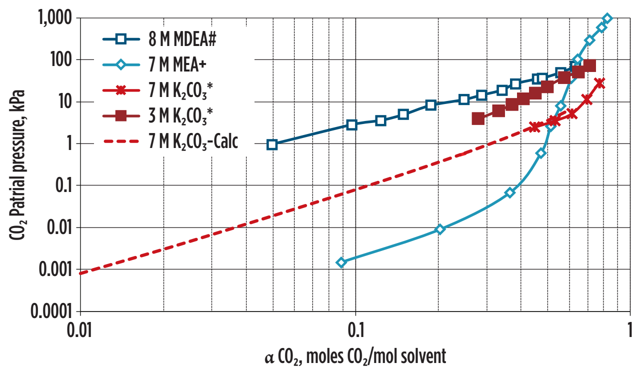

FIG. 2. CO_2 absorption in MDEA, MEA, and K_2CO_3 at 40°C.

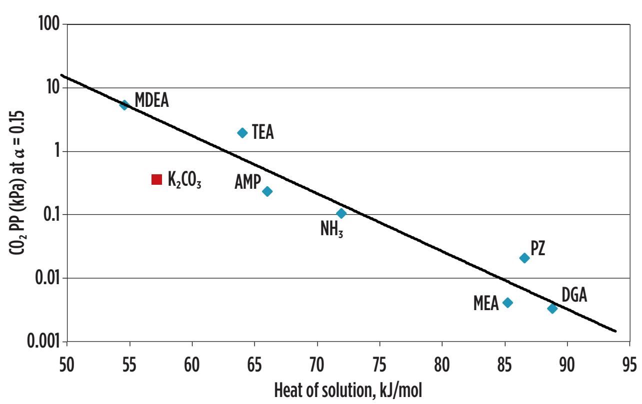

FIG. 3. Heat of solution of various solvents for CO_2 absorption.[11]

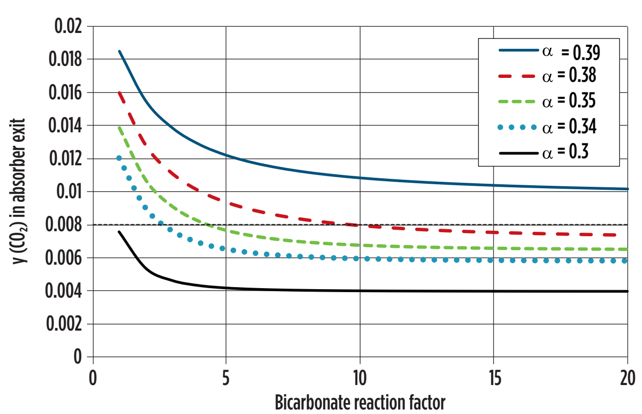

FIG. 4. Effect of lean loading and kinetic reaction rate on CO_2 absorption.

Cullinane and Rochelle[9] proved that the CO_2 absorption potential of the K_2CO_3 aqueous solution can be significantly improved with the addition of piperazine. Borhani *et al.*[10] compared DEA, monoethanolamine (MEA), diglycolamine (DGA), diisopropanolamine (DIPA) and methyldiethanolamine (MDEA) as promoters for the HPC process using rate-based simulations. They concluded that except for MDEA, which is too weak, all the other amines are good enough to be used as promoters in the HPC process, with MEA and DEA as the most cost-effective.

The rate-based model will incorporate the rigorous kinetic models, which account for the enhanced absorption rate with promoters. Different promoters show different levels in rate enhancement, and the model will use the reported enhancement data for model setup. The rigorous kinetic model enables better understanding of the process, adding confidence in proposed design improvements.

Characteristics of K_2CO_3 solvent. Mathias *et al.*[11] have summarized the desired characteristics of solvents based on one important solvent characteristic: the interplay between CO_2 capacity and heat of regeneration. A systematic analytical method was proposed to guide the selection of desired solvents based on systematic variation in CO_2 capacity and heat of solution of artificial solvents using the proprietary software[a].

In general, the desired solvent should have high absorption capacity but low heat of absorption. Potassium carbonate aqueous solution is a low-cost solvent with high stability and low heat of absorption. However, its solvent strength is low compared to most of the amines. As shown in **FIG. 2,** when the loading factor $\alpha < 0.5$ (mol CO_2/mol solvent), it demonstrates a stronger solubility of CO_2 than that of MDEA, but a weaker solubility than that of MEA. The predicted CO_2 partial pressures for 7 M K_2CO_3 in **FIG. 2** are based on a validated thermodynamic model. The appropriate industry application range is $0.1 < \alpha < 0.5$. Leaner loading ($\alpha < 0.1$) needs significantly more solvent. High CO_2 loading will saturate the solvent quickly, reducing absorption effectiveness.

FIG. 3 shows[11] a general trend in the relationship between the absorbent strength and heat of absorption with CO_2: the stronger the solvent, the higher the heat of solution. The CO_2 removal potential of K_2CO_3 is close to MDEA, which has the lowest heat of solution among the seven commonly used solvents.

Chemistry of the process. The chemistry of CO_2 absorption in K_2CO_3 can be expressed by the following three reactions (Eqs. 1–3):

$$\text{Equilibrium:} \quad 2H_2O \leftrightarrow OH^- + H_3O^+ \qquad (1)$$

$$\text{Kinetic:} \quad CO_2 + OH^- \rightarrow HCO_3^- \qquad (2)$$

$$\text{Equilibrium:} \quad H_2O + HCO_3^- \leftrightarrow CO_3^{-2} + H_3O^+ \qquad (3)$$

Reactions 1 and 3 are fast at Benfield or CATACARB process conditions and, therefore, are assumed to be at chemical equi-

librium. Reaction 2 models the absorption reaction of CO_2, which is slow and, therefore, considered to be a kinetically limiting reaction. Reaction 2 is the controlling step for CO_2 absorption with aqueous K_2CO_3.

The kinetic reaction (Eq. 2) is typically expressed by a power law-based kinetic model, as shown in a technical paper (Eq. 4):[2]

$$r = k\left(\frac{T}{T_0}\right)^n exp\left[\left(\frac{-E}{R}\right)\left(\frac{1}{T}-\frac{1}{T_0}\right)\right]\prod_{i=1}^{N} C_i^{a_i} \quad (4)$$

Mathias and Gilmartin[6] found that the simple Arrhenius temperature-dependent expression in Eq. 4 is inadequate to represent the reaction kinetics because it does not correctly model the equilibrium limit. They proposed a rigorous backward kinetic model (RBKM), which includes the activity coefficients of each components (Eq. 5):

$$r = k_0 \times exp\left[\left(\frac{-E}{R}\right)\left(\frac{1}{T}-\frac{1}{T_0}\right)\right] C_{CO_2} C_{OH^-}\left(1-\frac{a_{HCO_3^-}}{a_{CO_2} a_{OH^-} K_{eq}}\right) \quad (5)$$

where:

r = Rate of reaction, kmol/m^3.sec
k_0 = Rate constant for forward reaction (Eq. 3) at reference temperature T_0, m^3/kmol.sec
E = Reaction activation energy, kJ/kmol
C = Species concentration, kmol/m^3
a = Species activity, which is the product of mole fraction and activity coefficient
K_{eq} = Chemical equilibrium constant
R = Gas constant, 8.314462 kJ/kmol.K.

When a very large residence time is available for Reaction 2 (simulated with a large liquid holdup volume for kinetic modeling), both kinetic models (Eqs. 4 and 5) should reach the chemical-reaction equilibrium. Mathias and Gilmartin[6] indicated that only the RBKM reaches the true reaction equilibrium, while the simple power law expression (Eq. 4) reaches a false equilibrium. Therefore, the RBKM is used in this study when applying rate-based column modeling in the proprietary software.[a]

A major challenge for removing CO_2 with aqueous K_2CO_3 is that the absorption reaction rate is slow, which renders it uneconomical for commercial applications. Promoters have been used to increase the kinetic reaction rate.[7–10] In this study, the effect of promoters is quantified by the bicarbonate reaction factor (BRF) in rate-based column modeling. The BRF is defined as the ratio of promoted reaction rate over the unpromoted rate. To explore the effect of BRF on the overall CO_2 absorption in an absorber, a case study was conducted using a rate-based column model. The CO_2 absorption was simulated with different lean solvent loads (α = mol-CO_2/mol-solvent) over the range of BRF = 1–20. The result is illustrated in **FIG. 4.**

The results indicate that the most economically promoted reaction rate is to have BRF = 4–6, where the promoted kinetic reaction rate is close to the equilibrium rate. The additional promoted reaction rate (BRF > 6), with the additional cost of more promoters added, does not contribute to significant CO_2 ab-

sorption within the column. This provides a useful guideline for the dosage of promoters to be used during industrial operations.

Rigorous modeling with proprietary feature. Distillation and absorption are typically simulated with equilibrium stages, which is often not true in practice.[12] To account for the deviation from the equilibrium, tray efficiency is used in the simulation. However, selection of efficiency is an empirical choice, and the prediction methods for efficiency are often unreliable. In packed columns, HETP is used in place of the theoretical stage, which is also difficult to predict accurately.

In contrast, the rate-based distillation model simultaneously calculates mass and heat transfer rate, and accounts for the multicomponent interactions between diffusing species. It includes the well-known and accepted industry correlations to estimate the mass coefficients, liquid holdup and interfacial areas, as well as the heat transfer coefficients.

In Version 10 of the proprietary software[a], the Chilton and Colburn method[13] is normally used for heat transfer coefficients. The model calculates heat transfer coefficients from the binary mass transfer coefficients. In this study, this correlation is selected for all the cases to calculate the heat transfer coefficients. The Billet 93 method[14] is typically used for the liquid holdup calculation for random packings. The interfacial areas are calculated with the methods that are consistent with the correlations for mass transfer coefficients. This is where most process engineers may become confounded, as there are several options available for calculating mass transfer coefficients.

To help others use the rate-based column modeling, this study explores the different mass transfer correlation methods for the random packings employed in the specific model of the proprietary software used to simulate these methods[c]. The correlations for structured packings are excluded, as the validation data is not collected for the structured packings in this study. The model[c] has four options for mass transfer correlations to be used in random packed beds:

1. Billet 93
2. Brf 92 or Brf 82
3. Onda 68
4. Hanley Im10.

For detailed description of these correlations, please refer to the original publications.[14–17]

Rigorous model performance. The correlations used for mass transfer coefficients have been explored in rate-based column modeling[c]. The rate-based models are created to simulate the CO_2 absorbers, using K_2CO_3 aqueous solvent of both CATACARB and Benfield processes. The simulated results are compared with the reported operation data collected. The comparison is summarized in **TABLE 1** and **TABLE 2** for the random packings[d].

Recommendations. Based on the model performance[c] for random packings[d], the Brf 82 or Onda 68 mass transfer correlations are recommended for typical CO_2 removal processes, as both provide consistent predictions as compared to the reported data.

The consistent behavior of these two models are expected, as the Brf 82/Brf 92 is developed based on the Onda model. The purpose of this study is to provide insight on the selection of correlations for mass transfer coefficients when using rate-based modeling[a] for columns. A far-reaching evaluation of these mass transfer correlations requires more industry data to explore.

TABLE 1. Method comparison of random packings with CO_2 absorber of the CATACARB process

Correlation methods	Mass transfer correlation	Heat transfer correlation	Interfacial area method	Liquid holdup method	Predicted CO_2 content in overhead	Reported CO_2 content in overhead	Note
Billet 93	Billet 93	Chilton and Colbum	Billet 93	Billet 93	0.99 mol%	0.8 mol%	CL = 1.38 CV = 0.42
Brf 82	Bravo and Fair (1982)	Chilton and Colbum	Billet 93	Billet 93	0.86 mol%	0.8 mol%	No option for liquid holdup method
Onda 68	Onda 68	Chilton and Colbum	Billet 93	Billet 93	0.85 mol%	0.8 mol%	No option for liquid holdup method
Hanley Im10	Hanley Im10	Chilton and Colbum	Billet 93	Billet 93	0.92 mol%	0.8 mol%	No option for liquid holdup method

TABLE 2. Method comparison of random packings with CO_2 absorber of the Benfield process

Correlation methods	Mass transfer correlation	Heat transfer correlation	Interfacial area method	Liquid holdup method	Predicted CO_2 content in overhead	Reported CO_2 content in overhead	Note
Billet 93	Billet 93	Chilton and Colbum	Billet 93	Billet 93	0.11 mol%	0.1 mol%	CL = 1.38 CV = 0.42
Brf 82	Bravo and Fair (1982)	Chilton and Colbum	Bravo and Fair (1982)	Billet 93	0.106 mol%	0.1 mol%	No option for liquid holdup method
Onda 68	Onda 68	Chilton and Colbum	Onda 68	Billet 93	0.108 mol%	0.1 mol%	No option for liquid holdup method
Hanley Im10	Hanley Im10	Chilton and Colbum	Hanley Im10	Billet 93	0.14 mol%	0.1 mol%	No option for liquid holdup method

With the rigorous kinetic model incorporated and the recommended mass transfer correlation being used, the rate-based column modeling can provide accurate predictions of the absorber performance for either the CATACARB or Benfield process. The rate-based column model can be used to establish a reliable design basis for column internals and find the most cost-effective design for the column. The model can also provide a guide to unit operations, with the optimum operation range identified by a sensitivity study using a rate-based model. HP

NOTES

[a] AspenTech's Aspen Plus
[b] The RateSep module in Aspen Plus
[c] The Aspen Plus RadFrac model
[d] Random packings based on Sulzer NeXRing

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Monitoring hydrogen plant performance—Part 1

Process monitoring is an indispensable practice to keep track of key performance indicators (KPIs) of the hydrogen (H_2) plant. A good system of process monitoring not only ensures safe and reliable plant operations, but also helps in making strategic decisions such as catalyst changeout schedules. If KPIs are not monitored closely, there can be situations where the expected yields are not achieved. This affects the economics of the H_2 plant and that of the entire refinery complex, since the downstream hydrotreated/hydrocracked product yields are affected, as well. This will have a direct implication on the overall refinery margin.

For better monitoring and control, it is imperative to know the fundamentals of performance indicators. Performance monitoring requires operating data inputs from the plant, which are normally accessible from the intranet servers or from the distributed control system. It also requires stream analyses from the laboratory (or from online analyzers) to understand how each reactor is performing with respect to conversion/yield. The laboratory testing frequency of such streams is normally decided by the process engineering department in conjunction with the laboratory section.

The main objective of this article is to guide H_2 plant process engineers in:

- Performing a detailed mass balance across the H_2 flowsheet by using available information, such as dry analysis of outlet streams. Doing so will help identify bottlenecks across each reactor. The focus would be to see how much H_2 is being made before the final stream enters the pressure swing adsorption (PSA) unit. This mass balance will also help estimate the outlet stream's composition on a wet basis, thereby facilitating the estimation of equilibrium constants (K_{eq} values) for steam methane reforming (SMR) and water gas shift (WGS) reactions, which will help calculate the approach to equilibrium (ATE) values. These values, which are important in understanding the catalyst activity, can then be compared with the kinetic model values provided by the catalyst supplier.
- Monitoring other critical parameters and KPIs across each reactor in the H_2 flow sheet.

Feed definition and characterization. Two types of feed are considered for studying plant performance: Case 1 is a natural gas (NG) feed, and Case 2 is a naphtha feed. **Note:** The flow, composition and operating conditions are purely assumptions based on the author's experience and do not correspond to any specific plant.

For Case 1, feed comprising 1,000 kmol/hr of (NG + recycled H_2) is assumed to have the following composition:

- Hydrogen (H_2) = 2%
- Nitrogen (N_2) = 5%
- Methane (CH_4) = 90%
- Ethane (C_2H_6) = 2%
- Propane (C_3H_8) = 1%.

This combined stream of NG and recycled H_2 contains 10 ppmv of hydrogen sulfide (H_2S) and 5 ppmv each of methyl mercaptan and dimethyl disulfide (DMDS).

For Case 2, 80 kmol/hr of naphtha, with 20 kmol/hr of recycle H_2, is assumed. The most common laboratory information for naphtha is the ASTM D86 standard covering distillation and specific gravity. The ASTM D86 cut points of the assumed naphtha feed are:

- $T_{10\%}$ = 110°F
- $T_{30\%}$ = 128°F
- $T_{50\%}$ = 135°F
- $T_{70\%}$ = 145°F
- $T_{90\%}$ = 155°F.

The reported specific gravity is 0.716. Naphtha must be characterized further based on the above information. Degrees Fahrenheit and Kelvin will be used only for the following estimations.

Naphtha characterization. Eq. 1 is used to find the volume average boiling point (VABP):

$$(T_{10\%} + T_{30\%} + T_{50\%} + T_{70\%} + T_{90\%})/5 = 134.6°\text{F} \quad (1)$$

The correction factor is:

- Slope = $(T_{90\%} - T_{10\%})/80 = 0.563$
- $\text{Ln}\,\Delta = [-0.94402 - 0.00865\,(\text{VABP} - 32)^{0.6667} + (2.99791 \text{ x slope}^{0.333})]$
- $\Delta = 3.825°\text{F}$.

The mean average boiling point (MeABP) is shown in Eq. 2:

$$\text{MeABP} = \text{VABP} - \Delta = 134.6 - 3.825 = 130.8°\text{F} = 328.03°\text{K} \quad (2)$$

The molecular weight is calculated using Eq. 3:

$$1.6607 \text{ x } 10^{-4} \times (\text{MeABP})^{2.1962} \times (\text{specific gravity})^{-1.0164} = 1.6607 \times 10^{-4} \times (328.03)^{2.1962} \times (0.716)^{-1.0164} = 78.2 \text{ kg/kmol} \quad (3)$$

The carbon/hydrogen (C/H) weight ratio is calculated using Eq. 4:

$$3.4707\,[\exp^{\{(0.01485\,T_b + 16.94\text{x}\,(\text{specific gravity}) - 0.012492\,T_b \times (\text{specific gravity})\}} \times T_b^{-2.725} \times (\text{specific gravity})^{-6.798}] \quad (4)$$

Substituting T_b = MeABP; therefore, the C/H weight is 6.022.

The molar H/C = 12.01/(C/H weight), which equals 1.9944. The empirical formula of naphtha is $CH_{1.9944}$. The empirical molecular weight is shown in Eq. 5:

$$1 \times 12 + 1.9944 \times 1.008 = 14 \quad (5)$$

The carbon number of naphtha is found by using Eq. 6:

$$\text{Actual molecular weight/empirical molecular weight} = 78.2/14 = 5.586 \quad (6)$$

Feed purification, Section 1: Hydrogenator. The feed, along with recycled H_2, first enters the hydrogenator reactor. One of the primary functions of the hydrogenator is to convert organic sulfur (S) compounds (e.g., mercaptans, sulfides, disulfides and thiophenes) to H_2S. Other primary functions are to convert organic chlorides (if present) to hydrochloric acid (HCl) by reacting with H_2 and to hydrogenate olefins that may be present in the feed.

Key parameters to be monitored include:

- H_2 level for each type of feed or combination of feeds. This level is generally suggested by the catalyst supplier. The process engineer should confirm this level with the catalyst supplier in case of any deviation in feed specifications. The recommended H_2 level in the outlet stream is normally 2% for NG feeds and about 26% for highly aromatic naphtha feeds.
- The optimum operating temperature is 350°C–400°C (662°F–752°F). For the LPG feed, the maximum temperature limit may be lower due to susceptibility to form carbon. Operating higher than the recommended maximum temperature may cause carbon deposition on the catalyst and upstream pre-heat coil, leading to high pressure drop issues. Operating lower than the recommended minimum temperature may cause organic sulfur or chloride to slip through and poison the downstream reforming catalysts.

Among the KPIs is pressure drop. Being the first reactor in a typical H_2 flow sheet, the hydrogenator is vulnerable to pressure drop issues. Some general reasons for increases in pressure drop across any fixed bed include:

- Breakage or erosion of catalyst particles, primarily due to poor handling and loading, is one of the causes of high pressure drop.
- Disintegration of catalyst pellets—primarily the top layer—is another cause of pressure drop due to poor inlet gas distribution and/or an inadequate hold-down layer on the top. In some cases, the disintegration of poor-quality support balls in the hold-down layer contributes to high pressure drop.
- Carryover on the catalyst bed is one of the most likely reasons for high pressure drop across the hydrogenator. Any debris upstream of the reactor, if not properly removed, can get carried over to the top of the catalyst, leading to a high pressure drop. Specialized foulant trapping materials are commercially available to address this issue.
- Deformation of catalyst pellets due to accidental wetting of the catalyst, causing a decrease in catalyst strength, can lead to deformation and, in the worst case, disintegration. This issue can be encountered in high-temperature or medium-temperature shift reactors where there is a likelihood of upstream boiler water leaks.
- The collapse of the bed support grid or any damage to the outlet collector can result in a significant pressure drop.
- Operating the reactor (hydrogenator and pre-reformer) at higher than recommended temperatures can cause thermal cracking of the hydrocarbon feed, thereby depositing carbon over the catalyst, leading to a high pressure drop. In addition, for pre-reformers processing naphtha feeds, there is a minimum bed temperature below, which could have issues of polymeric carbon formation that can lead to pressure drop increases.

It is important to monitor the pressure drop trend closely from the time the catalyst has been put in operation. If the pressure drop increases suddenly, then that time (before and after) should be isolated and investigated in detail. This generally applies to all reactors in the flowsheet.

Inlet and outlet chlorides and sulfur. It is important to monitor the inlet and outlet levels of chlorides and sulfur. In most H_2 plants, the feed is analyzed daily, so the total inlet chlorides and sulfur are known. The outlet H_2S and HCl can be routinely measured by process engineers using detector tubes, or they can be analyzed in a laboratory. The outlet H_2S measurement will help determine if the hydrogenator is converting all organic sulfur to H_2S.

For example, if the feed (NG + recycle H_2) in Case 1—containing 10 ppmv of H_2S and 5 ppmv each of methyl mercaptan and DMDS—is passing through the hydrogenator, then the outlet should measure the calculated H_2S value in Eq. 7:

$$10 \text{ ppmv } H_2S + 5 \text{ ppmv} \times 1 \text{ (methyl mercaptan)} + 5 \text{ ppmv} \times 2 \text{ (DMDS)} = 25 \text{ ppmv of } H_2S \quad (7)$$

Feed purification, Section 2: Chloride absorber. This section is not common and is only required when the feed contains chlorides. The primary function of the chloride absorber is the absorption of HCl, which is either present in the feed or formed across the hydrogenator. In most cases, this catalyst is installed as a small layer below the hydrogenator. In some flowsheets, it is also installed above the H_2S absorber. KPIs include the following:

- Outlet chloride should be less than 0.1 ppmv vs. inlet chloride.
- The catalyst life depends on pickup/capacity. The process engineer should have the information of expected pickup from the catalyst supplier.

Feed purification, Section 3: H_2S absorbers (zinc oxide). The primary function of the H_2S absorbers is to absorb H_2S, which is present either in the feed or formed across the hydrogenator. This section is usually seen as two vessels in a lead-lag arrangement or as a single vessel when sulfur levels are very low. In addition to pressure drop, KPIs include the following:

- Outlet H_2S should be less than 0.1 ppmv vs. inlet H_2S.
- The catalyst life depends on pickup/capacity. The process engineer should have the information of expected pickup from the catalyst supplier.

Note: The process engineer should ask the catalyst supplier for actual pickup and not theoretical pickup. The theoretical pickup might be much higher than the actual pickup.

For example, Case 1—1,000 kmol/hr of (NG + recycle H_2) with 25 ppmv of H_2S—would have a theoretical pickup of 600 kgS/m^3 and an actual pickup of 500 kgS/m^3. To reiterate, the pickup figures are an assumption and do not correspond to any specific product.

The volume of each bed is 10 m^3. Eq. 8 is used to calculate the amount of sulfur to be removed:

$$(25/1{,}000{,}000) \times 1{,}000 \text{ kmol/hr} \times 24 = 0.6 \text{ kmol } H_2S\text{/day} \\ = 20.4 \text{ kg } H_2S\text{/day} = 20.4 \times 32/34 = 19.2 \text{ kgS/day} \quad (8)$$

Therefore, the expected life is calculated using Eq. 9:

$$500 \text{ kgS/m}^3 \times 10 \text{ m}^3/19.2 = 260 \text{ days} \quad (9)$$

The most economical way of operating a lead-lag arrangement is to allow the lead bed to operate until near saturation—i.e., until the outlet H_2S from the lead bed is 90% of the inlet H_2S.

Feed purification, Section 3: Ultra-purification. This section is not common in all flowsheets. The primary function of this section is to purify H_2S to parts per billion (ppb) levels. It is usually seen as a small layer beneath the zinc oxide absorber(s). KPIs include the following considerations:

- It may be difficult to measure very low ppb levels of H_2S by using detector tubes or the laboratory. However, the economic benefit of having this layer can be realized in terms of extended life of the pre-reformer catalyst. Ultra-purification also helps extend the life of primary reformer catalysts in highly stressed reformers.
- H_2S pickup/capacity is another KPI.

Pre-reformers. Pre-reformers are not found in all flowsheets. The most important benefit of a pre-reformer is the flexibility to process different feeds. The primary function of the pre-reformer is to convert C_2+ in the feed to C_1 and H_2. The key parameters include the steam-to-carbon (S/C) ratio, inlet temperature, pressure, Z_{90} progression and pressure drop. Z_{90} is an important trend that needs to be monitored closely, since it determines the timing of the pre-reformer catalyst changeout. The typical Z_{90} plots for NG and naphtha feeds are shown in **FIGS. 1** and **2.**

KPIs include C_2+ slip, pressure drop and Z_{90} progression. ATE is not a KPI for the pre-reformer, as the SMR's ATE would be close to zero throughout the expected life of the catalyst if the C_2+ is within the guaranteed limit. However, the SMR and WGS equilibrium temperatures can be calculated and compared with the observed temperatures.

Mass balance across the pre-reformer. Case 1—1,000 kmol/hr of treated (NG + recycled H_2)—has the following composition:

- H_2 = 2%
- N_2 = 5%
- CH_4 = 90%
- C_2H_6 = 2%
- C_3H_8 = 1%.

The inlet S/C ratio (mol/mol) is 3, the outlet pressure is 24.2 bara (23.9 atma), the inlet temperature is 450°C, and the outlet temperature is 400.2°C. The outlet composition (dry basis) reported by the laboratory is:

- H_2 = 18%
- N_2 = 4%
- CH_4 =73%
- CO = 0.03%
- CO_2 = 5%.

The unknowns include the outlet dry flow rate and the outlet steam, and it is not known how much steam has been consumed in the reactions to make products.

The inlet and outlet moles for Case 1 are shown in **TABLE 1.** In this example, *d* is the outlet dry flow rate, and *s* represents the moles of steam at the outlet. To calculate *d* using carbon balance, Eq. 10 is used:

$$900 + 20 \times 2 + 10 \times 3 = 0.73d + 0.05d + 0.0003d \quad (10) \\ d = 1{,}243.11 \text{ kmol/hr}$$

To calculate *s* using oxygen balance, Eq. 11 is used:

$$2{,}910 = 2 \times 0.05 \times 1{,}243.11 + 0.0003 \times 1{,}243.11 + s \quad (11) \\ s = 2{,}785.3 \text{ kmol/hr}$$

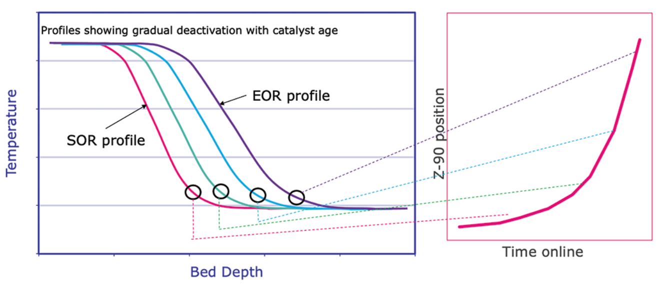

FIG. 1. Z_{90} plot for NG feed.

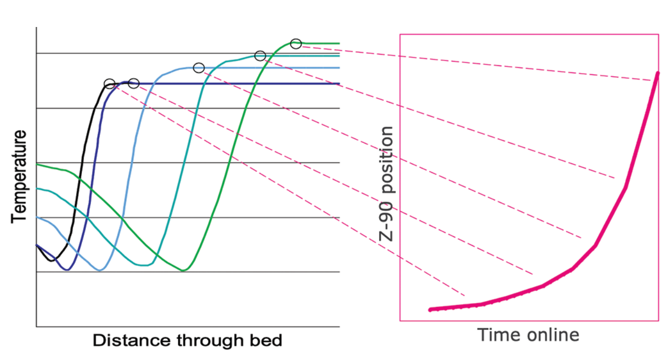

FIG. 2. Z_{90} plot for naphtha feed.

TABLE 1. The inlet/outlet moles for Case 1

	Inlet moles, kmol/hr	Outlet moles, kmol/hr
H_2	20	0.18*d*
N_2	50	0.04*d*
CH_4	900	0.73*d*
C_2H_6	20	0
C_3H_8	10	0
CO_2	0	0.05*d*
CO	0	0.0003*d*
H_2O	3 x [900 + 20 x 2 + 10 x 3] = 2,910	*s*

TABLE 2. Data for outlet wet mol fraction

	Inlet, kmol/hr	Outlet, kmol/hr	Outlet wet mol fraction
H_2	20	223.76	0.056
N_2	50	49.72	0.012
CH_4	900	907.47	0.225
C_2H_6	20	0	0
C_3H_8	10	0	0
CO_2	0	62.16	0.015
CO	0	0.37	0.000093
H_2O	2,910	2,785.32	0.691

TABLE 3. Inlet/outlet moles for Case 2

	Inlet moles, kmol/hr	Outlet moles, kmol/hr
H_2	20	0.215*d*
Naphtha carbon	80 x 5.586 = 446.88	0
H_2O	3 x 446.88 = 1,340.64	*s*
CO_2	0	0.24*d*
CO	0	0.005*d*
CH_4	0	0.54*d*

TABLE 4. Data for outlet wet mol fraction

	Inlet, kmol/hr	Outlet, kmol/hr	Outlet wet mol fraction
H_2	20	122.39	0.0749
Naphtha carbon	446.88	0	0
H_2O	1,340.64	1,064.53	0.6517
CO_2	0	136.63	0.0836
CO	0	2.85	0.00174
CH_4	0	307.41	0.1882

The total wet outlet flow (**TABLE 2**) is calculated in Eq. 12:

$$1{,}243.11 + 2{,}785.3 = 4{,}028.4 \text{ kmol/hr} \quad (12)$$

To calculate the SMR equilibrium constant, Eq. 13 is used:

$$\text{Kp (SMR)} = P^2 \times ([CO]\,[H_2]^3)/[CH_4][H_2O] = 23.9^2 \times (0.000093 \times 0.056^3)/(0.225 \times 0.691) = 6 \times 10^{-5} \quad (13)$$

Eq. 13 can be substituted with Eq. 14 to obtain equilibrium temperature in °K²:

$$\text{Ln}\,(1/Kp) = 0.2513Z^4 - 0.3665Z^3 - 0.58101Z^2 + 27.1337Z - 3.277 \quad (14)$$

where:

$Z = (1{,}000/T)^{-1}$—T is in °K

$\text{Ln}\,(1/Kp) = \text{Ln}\,(1/6 \times 10^{-5}) = 9.721$

The equation can be solved using Excel: Z = 0.485; T_{eq} = 673.4°K (400.2°C). Therefore, the approach to SMR equilibrium in the pre-reformer is measured outlet temperature – equilibrium temperature = $T - T_{eq}$ = 400.2 – 400.2 = 0°C.

A similar balance is done in Case 2 for treated naphtha feed. Case 2 feed is 80 kmol/hr of naphtha (estimated *C* number of 5.586), an S/C ration of 3 mol/mol, an outlet pressure of 24.1 bara (23.8 atma), an inlet *T* of 450°C and an outlet *T* of 477°C. The outlet composition (dry basis) reported by the laboratory was the following:

- H_2 = 21.5%
- CH_4 = 54%
- CO = 0.5%
- CO_2 = 24%.

The unknowns include the outlet dry flowrate and the outlet steam, and it is not known how much steam has been consumed in the reactions to make products.

To reiterate, *d* is the outlet dry flowrate, and *s* are the moles of steam at the outlet. The inlet and outlet moles for Case 2 are shown in **TABLE 3.** To calculate *d* using carbon balance, Eq. 15 is used:

$$446.88 = 0.24d + 0.005d + 0.54d \quad (15)$$
$$d = 569.3 \text{ kmol/hr}$$

To calculate *s* using oxygen balance, Eq. 16 is used:

$$1340.64 = s + 2 \times 0.24 \times 569.3 + 0.005 \times 569.3 \quad (16)$$
$$s = 1{,}064.53 \text{ kmol/hr}$$

The total wet outlet flow (**TABLE 4**) is calculated using Eq. 17:

$$569.3 + 1064.53 = 1{,}633.83 \text{ kmol/hr} \quad (17)$$

To calculate the SMR equilibrium constant, Eq. 18 is used:

$$Kp\text{ (SMR)} = P^2 \times ([CO]\,[H_2]^3)/[CH_4][H_2O] = 23.8^2 \times (0.00174 \times 0.0749^3)/(0.1882 \times 0.6517) = 3.38 \times 10\text{–}3 \quad (18)$$

Eq. 18 can be substituted with Eq. 19 to obtain the equilibrium temperature in °K²:

$$\text{Ln}\,(1/Kp) = 0.2513Z^4 - 0.3665Z^3 - 0.58101Z^2 + 27.1337Z - 3.2770 \quad (19)$$

where:

$Z = (1000/T)^{-1}$—T is in °K

$\text{Ln}\,(1/Kp) = \text{Ln}\,(1/3.38 \text{ x } 10^{-3}) = 5.691$

The equation can be solved using Excel: Z = 0.333; T_{eq} = 750°K (476.9°C). Therefore, the approach to SMR equilibrium in the pre-reformer is $T - T_{eq}$ = 477 – 476.9 = 0.1°C.

Part 2. Part 2 will be featured in the November issue of *Hydrocarbon Processing.* HP

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BEST AR/VR/AI TECHNOLOGY

Aspen AIoT AIoT™ Hub, Aspen Technology

The Artificial Intelligence of Things (AIoT) is a cloud-ready and built-for-purpose industrial AI infrastructure that unlocks the immense value from data assets across capital-intensive enterprises to deliver actionable insights quickly and easily.

AVEVA™ Schedule AI Assistant, AVEVA

The AI system provides refinery schedulers a smooth and incident-free means to optimize refining operations, providing viable options for plant scheduling in a matter of minutes instead of hours when using older methods.

ehsAI, ehsAI

The system uses AI and machine learning (ML) to automate the transformation of regulatory documents such as patents, standards, regulations, policies and guidance documents into detailed, mapped requirements.

Immersive Field Simulator (IFS), Honeywell

The IFS is a VR and mixed reality-based training tool that incorporates a digital twin of the physical plant to provide targeted, on-demand and skill-based training for plant workers.

Closed Loop Neural Network™, Imubit

This solution is a closed-loop neural network that interconnects planning and economics, process engineering, process control and operations, enabling plant managers to discover, engineer and monetize process optimization opportunities.

APM 360™, Symphony Industrial AI

This technology covers overall machine health and performance, real-time prescriptive monitoring and predictive maintenance insights for critical plant assets.

BEST ASSET MONITORING TECHNOLOGY

Aspen Mtell® v12, Aspen Technology

This prescriptive maintenance solution uses historical behavior of an asset and maintenance data to find key failure events and help organizations discover problems before failures occur.

Honeywell Forge Asset Performance Management (APM), Honeywell

The APM tool is an enterprise-grade, real-time analytics solution that monitors asset and process performance, detects impending health issues and helps drive continuous improvement.

Digital Reliability Platform, SCG Chemicals/AVEVA

SCG Chemicals worked with AVEVA on a digital solution to monitor critical assets and predict failure, which would have a detrimental impact to SCG's production chain. The asset performance management platform predicts equipment health, monitors performance and enables advanced maintenance to eliminate unplanned downtime.

APM40&G, Siemens Energy

This solution helps personnel avoid costly downtime, obtain enhanced performance out of assets and significantly reduce operations by continuously comparing real-time operational data against models.

Dynamic Risk Pathways, Sphera

This technology is the industry's next generation of operational risk management digital twin technology to model and simulate risk exposure to help prevent incidents.

BEST AUTOMATION TECHNOLOGY

Aspen GDOT™, Aspen Technology

The General Dynamic Optimization Technology (GDOT) addresses the long-standing challenge of margin leakage in refineries and olefin plants by coordinating and optimizing multiple proess units, covering broad process envelopes, all in a closed loop.

Collaboration Information Server, Yokogawa

CI Server automatically aggregates data that has been acquired from plant facilities and systems to enable personnel to monitor and operate plant operations remotely. The solution provides users all the information needed to make swift and effective decisions to plant operations.

BEST CATALYST TECHNOLOGY

ART ICR 5th Generation ISODEWAXING® catalyst, Advanced Refining Technology

This fifth-generation ISODEWAXING catalyst overcomes current base oil manufacturing challenges. It uses an advanced shape-selective zeolite technology to improve base oil yield and allow higher contaminant feedstock.

ACTION®+ FCC Catalysts, Albemarle

This FCC catalyst leverages the core technology of ACTION catalysts—the shape selective ZT-400—in conjunction with a new, innovative Y-zeolite stabilization system (ZT-500). This minimizes hydrogen transfer reactions, providing maximum LPG olefinicity with unrivaled butylene/propylene selectivity and preserving those species which maximize gasoline octane.

SeLene™, Axens

This catalyst portfolio provides optimal performance for selective hydrogenation. The catalyst family combines more than 20 industrially proven catalysts to create value along the whole olefin value chain from acetylene to the pygas cut.

Ziegler-Natta Catalysts for Polypropylene Production, Reliance Industries Ltd.

This catalyst optimizes polypropylene production by providing desired polymerization and product performance.

FUSION® FCC Catalysts, W. R. Grace & Co.

This next-generation FCC catalyst employs a novel advanced matrix binding system designed to enhance product yields for refineries processing residuum feedstocks.

BEST CYBERSECURITY PROGRAM/SOFTWARE

Advanced Monitoring and Incident Response, Honeywell

The AMIR service provides 24/7 operational technology cybersecurity detection and rapid response for current and emerging cyber threats.

S. WYSS, Bechtel Corp., Houston, Texas

Materials management: Data-centric execution to enhance organizational productivity—Part 1

As a veteran of many capital projects once observed, "All projects execute materials management—those that do so without a plan and the appropriate resources just do it very poorly." What is materials management? Ask a dozen materials managers and you will probably get a dozen different definitions. While we generally think of capital projects in terms of design and construction, the materials required to execute projects heavily impact both design and construction—not only in terms of executional information, but also in terms of execution planning.

Materials management efforts have generally been related to improving materials-related information flows to design and construction. In recent decades, these efforts have fallen short for two primary reasons: the lack of recognition that materials management is an integral part of project management, and the failure to support change in entrenched siloed materials-related work processes as data connectivity has improved. As a result, the potential of optimal materials management has not been fulfilled.

With the current trend of transitioning from document-centric execution to data-centric execution, it is important that engineering, procurement and construction (EPC) organizations recognize that the cross-functional executional perspective of materials management offers opportunities for data-centric-based transformational work-process change—and for significant productivity enhancement. Those organizations that attempt to manage this change from EPC siloes will suffer.

Part 1 of this series will briefly address the broad concept of materials management and will discuss materials management as an investment and as an attitude. It will also provide examples that illustrate the hidden costs of poor materials management execution. Part 2—to be published in the November issue of *Hydrocarbon Processing*—will show how data-centric execution, with an object-oriented focus and exposure to a common data environment (CDE), fosters elevation out of detrimental siloed document-centric execution. Additionally, Part 2 will detail how collaboration among all transactional parties via a CDE—not just EPC and project controls, but also suppliers, service providers and the owner/client—can facilitate efficient project execution. Finally, Part 2 will highlight several areas where a forward-thinking materials management team can identify and drive transformational work process opportunities via an object-oriented approach to offer significant productivity enhancement.

What is—and is not—materials management? The Construction Industry Institute (CII) is the unparalleled authority on materials management, with numerous and thorough publications spanning decades, documenting benefits of rigorous and robust materials management project execution. As CII documents show, materials management is not just procurement or warehousing, although both are elements. Materials management is the cross-functional work process coordination of materials-related work processes across engineering, procurement and construction to optimize those processes for the unique project-specific needs to deliver the lowest total installed cost (TIC) to the project. FIG. 1 provides an overview of the four phases of materials management and the steps that comprise each phase. FIG. 2 shows the parties that play roles in projects.

In the past, many EPC contractors have embraced the idea of materials management without recognizing that they were already executing it—just in a fractured, siloed and often inefficient manner. Concerns that adding a materials management team to project execution would add undesired bureaucracy have led many to create a narrow materials management team to mop up and close work process gaps, instead of positioning the team to prevent these gaps from ever materializing in the first place. In addition, positioning the materials management team to report to a manager besides the project manager, and specifically not providing this team the latitude to participate in all aspects of the project where materials-related decision making is taking place, has led to many lost opportunities in identifying subtle upstream

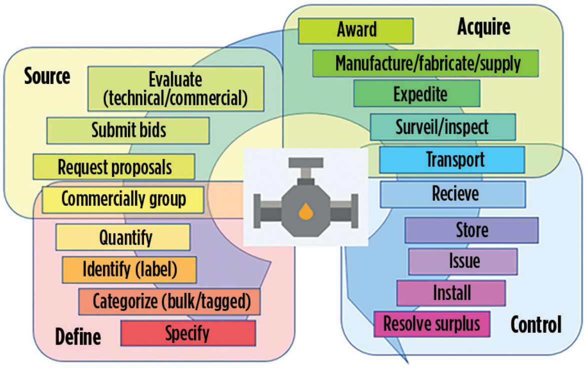


FIG. 1. Phases/steps of materials management.

work process modifications that could capture downstream order-of-magnitude cost savings. This narrowly-focused materials management practice can also cause work process gaps to occur that can significantly impact downstream execution.

Materials management as an investment: The railroad analogy. Just as freight delivered by a single train can supplant hundreds of trucks at order-of-magnitude savings, a thoughtful, structured and disciplined materials management execution effort can optimize project execution and deliver the lowest TIC. However, just as each major route of a railroad needs to meet the specific needs of that route, and to be maintained and resourced to keep the tracks operational, materials management execution must be well thought out and structured relative to the overall needs of the organization, as well as to the specific needs of the project. Executing parties must also be disciplined to recognize that increased upstream resources may be needed to save on downstream costs. There must be an attitude recognizing that each party works to optimize overall project efficiency. EPC organizations that allow upstream lapses or gaps to occur, only to remediate or close the gaps downstream with cleanup resources, are no different than a railroad company that waits for a train to derail to find issues with the track. While it might be tempting to think that, once the plan is in place, it will self-execute, projects need a lean materials management team to see that execution proceeds as planned, and to look for the inevitable and/or unforeseen materials-related twists and turns in project execution that can impact execution.

Materials management as an attitude: A parallel to safety. Several decades ago, construction teams employed safety teams that amounted to "safety policemen," reporting to construction management. Construction managers and superintendents often pushed the limits of safety to complete the job. The safety engineers were left to police unsafe behavior, with some safety concerns disregarded by construction management—as safety was considered subservient to production. At the turn of the century, however, there was an awakening within the construction industry, and attitudes changed to recognize that everyone was responsible for safety—not just the safety organizations—and that safety superseded production. Due to this attitude change, project safety organizations are lean (but effective) teams, consisting of a safety manager (who reports to project management) and resources to provide training. At present, everyone polices safety on a project.

Organizations that recognize that materials management is the sum of the phases and steps detailed in **FIG. 1,** and that also recognize that the sub-disciplines within the EPC teams have a responsibility to execute their respective steps to facilitate overall project optimization—as opposed to optimizing their individual steps (i.e., working separately in siloes)—will achieve the highest level of efficiency and deliver the lowest TIC. As projects need to employ a lean safety team, with a leader reporting directly to project management, EPC contractors will achieve the highest levels of efficiency when they recognize that materials management is not just a subset of procurement but also a resource to project management. In fact, if you remove "materials related" from the term's definition previously provided, you will have defined project management. Materials management is a specialized subset of project management—it is focused on the wide and diverse set of project activities that are touched by materials.

A lean materials management team: A resource, not an empire. With even the most open-minded team of design engineers, designers, procurement professionals, field engineers and superintendents, asking each to understand all the interrelated aspects of the materials management process is not reasonable. Each project must have a lean materials management team consisting of a materials manager (who reports directly to the project manager), along with a small staff that is knowledgeable of the work processes. This team will participate in the ongoing project execution and will attend meetings focused on:

- Providing early identification of opportunities to optimize and/or capture upstream materials-related work process changes that will offer order-of-magnitude downstream savings
- Monitoring materials management execution by transactional parties in engineering, procurement and construction to watch for minor materials-related protocol deviations and communication gaps that might negatively impact project productivity
- Preparing cross-functional project-specific work process reports to management that identify hidden work process issues.

For example, a well-developed materials management effort entails upstream protocols that support and align with downstream protocols. Small changes in the design process (such as providing or omitting data in the model) can enhance or starve construction intelligence. Minor or subtle changes in the way materials are identified can impact downstream system tools with a disastrous effect. Meetings—such as purchase order (PO) award kickoff meetings—with suppliers (generally led by the procurement organization) must have someone present to see that all aspects of the planned PO execution (specifically aspects of supplier scheduling, delivery and shipment) facilitate information flow to the project to facilitate construction planning. The bottom line is that the optimal materials management team is a resource with no transactional duties at all. This team is there to ensure that each transactional party (**FIG. 2**) executes their respective role to optimize project efficiency.

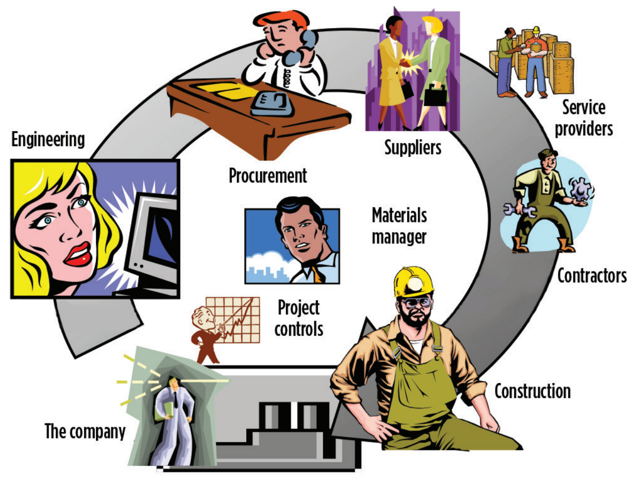


FIG. 2. Parties that play a role in materials management.

The hidden impact of poor materials management. Large capital projects employ hundreds of EPC professionals. These projects entail collaboration not only with the client/owner, but also with suppliers and subcontractors, and they are complex in execution. Minor upstream inefficiencies can and do generate a significant downstream impact. Many times, these inefficiencies are not discernable, and are simply swept under the proverbial rug and unnecessarily written off as just the cost of doing business. The following are a few examples, but these are just the tip of the iceberg.

Missed materials identification (ID) causing construction schedule changes. Piping design, along with the supply and erection processes, are major aspects of process plant project execution. EPC contractors began delivering data-centric piping design two decades ago. This process, while one of the most complex in a process plant project, is also highly automated and efficient. Piping materials are highly standardized, but some large-diameter components—specifically, flanges larger than 24 in.—can be supplied to numerous standards. Projects have historically had issues with large-diameter flanges being properly installed, and guiding these installations are the API-605 (Large-Diameter Carbon Steel Flanges) and MSS-SP44 (Steel Pipeline Flanges) standards. Improper flange installation is often not caught until the piping is ready for installation—causing the project to be delayed and new costs incurred due to the need to cut and re-weld large flanges.

On a project with a very logistically challenged site location, this concern was raised without a thorough root cause analysis. Instead of having the piping discipline requisition for these large-diameter flanges in accordance with their standard protocols, the mechanical discipline added these flanges to any equipment order that required large-diameter flanges, and the equipment supplier would provide the mating flange.

The project materials manager joined the project after this decision was made. The materials manager pointed out that the root cause was poor execution and not supply, and that the mechanical discipline's materials ID protocols did not conform with the piping discipline's protocols. The materials manager received project concurrence to revert to a standard protocol where the piping team requisitioned these flanges—or so he thought.

This project was a large gas plant, with numerous sizable compressors, a large central pipe rack with fin fan coolers on top, compressors on one side of the rack and suction drums on the other side, connected by 54-in. to 72-in. interconnecting piping. Detailed construction planning was only being performed 2 mos–3 mos ahead of execution. The construction team was utilizing a large 400-t crane to put in place equipment and large piping. The crane was positioned in a sub-area adjacent to the pipe rack. The crane would work adjacent to the sub-areas and then would be moved several sub-areas down the plant. Moving the crane involved a crew of 10 and a full day of work.

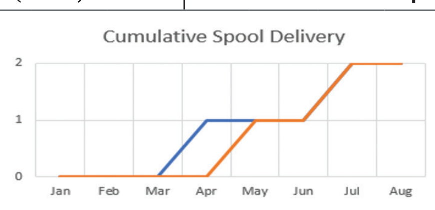
Two months before the construction team wanted to install large-diameter compressor piping, which required the 400-t crane, it came to light that the 54-in. and 72-in. pipe spools would not be on site in time. An investigation showed that the

TABLE 1. A tale of two spools: Cascade vs. priorities

		Fabricator cascade allocation						EPC priorities allocation								Monthly inventory/ order status		
		Spool 1			Spool 2			Spool 1				Spool 2						
		Required: May			Required: July			Required: May				Required: July						
		2-mos fabrication cycle			2-mos fabrication cycle			2-mos fabrication cycle				2-mos fabrication cycle						
Month	Item	Spool takeoff	Issued	Spool status	Spool takeoff	Issued	Spool status	Spool takeoff	Allocated	Issued	Spool status	Spool takeoff	Allocated	Issued	Spool status	Received	On order	Order ETA
Jan	Pipe	1		Not resolved	1		Not resolved	1	1		Not resolved	1			Not resolved	1	1	May
	Elbow	1						1									1	Mar
	Tee				1							1	1				1	Feb
Feb	Pipe	1		Not resolved	1	1	In fabrication	1	1		Not resolved	1			Not resolved	1	1	May
	Elbow	1						1									1	Mar
	Tee				1	1						1	1			1		
Mar	Pipe	1		Not resolved	1	1	In fabrication	1		1	In fabrication	1			Not resolved	1	1	May
	Elbow	1						1		1						1		
	Tee				1	1						1	1			1		
Apr	Pipe	1		Not resolved	1	1	Delivered	1		1	In fabrication	1			Not resolved	1	1	May
	Elbow	1						1		1						1		
	Tee				1	1						1	1			1		
May	Pipe	1	1	In fabrication	1	1	Delivered	1		1	Delivered	1		1	In fabrication	2		
	Elbow	1	1					1		1						1		
	Tee				1	1						1		1		1		
Jun	Pipe	1	1	In fabrication	1	1	Delivered	1		1	Delivered	1		1	In fabrication	2		
	Elbow	1	1					1		1						1		
	Tee				1	1						1		1		1		
Jul	Pipe	1	1	Delivered	1	1	Delivered	1		1	Delivered	1		1	Delivered	2		
	Elbow	1	1					1		1						1		
	Tee				1	1						1		1		1		

	Fabricator cascade allocation	EPC priorities allocation
Delivery Effect	**Early spools count:** 1 (3 mos)	**Early spools count:** 0
	On time spools count: 0	**On time spools count:** 2
	Late spools count: 1 (2 mos)	**Late spools count:** 0

Delivery Curve



spools had not gone into fabrication because the materials management system indicated that the large-diameter flanges had not been requisitioned. It turned out that these flanges had been requisitioned, but this was before the materials manager joined the project. The flanges were requisitioned by the mechanical discipline—not by the piping discipline—and not in accordance with piping discipline protocols, so they were invisible to the system. Therefore, the spools had not yet been fabricated.

The project team quickly retrieved the flanges—which had been sitting at the vessel fabricator facility for more than a year—and sent them to the spool fabricator, who quickly fabricated the spools. However, due to logistical issues, the spools arrived on site 2 mos late. The net effect was that the construction team had to leave the area where the 400-t crane was needed to move the crane back to the place where these large-diameter spools had to be positioned. This caused a reshuffle of the entire construction schedule and delayed operations by a full day. No one quantified the cost of this delay, but it does not

take much imagination to see the large impact and cost that this simple but poorly thought-out engineering decision incurred.

Passive management of pipe spool fabrication. Of the four basic categories of materials (major equipment, fabricated systems, standard components and consumables), fabricated systems require the highest level of collaboration and they suffer the most when the EPC contractor passively manages the process. Fabricated systems can take many forms, but the two most prevalent in a process plant are pipe spools and structural steel.

With the piping design, the supply, fabrication and erection processes are almost always on a secondary critical path, if not the primary path—and EPC contractors who actively engage with pipe spool fabricators reap a smoother construction path, particularly where the materials management team takes the lead.

In another example, two projects were being executed in parallel for the same client. Each project had similar scopes and logistical challenges, but were managed by two different project teams. Both projects awarded the fabrication PO to the same fabricator, and, due to their compressed schedules and logistical challenges, both chose to free-issue spool materials for fabrication as opposed to relying on the fabricator to supply the spool materials.

Project A took a passive approach, with the procurement organization managing the spool fabricator. While its procurement team shared high-level priorities with the fabricator, assuming that the spool component materials would be received upon shipment, it did not integrate systems with the fabricator. Instead, this team relied on the fabricator to work according to project priorities by using the fabricator's standard cascade allocation execution. Unsatisfactories, overs, shorts and deficiencies (UOS&Ds) were not addressed upon shipment receipt. The project team produced delivery curves from its sophisticated materials management tool, but only at the ISO level, as that was the finest granularity that the project engineering team could deliver.

Project B had its materials manager manage the spool fabricator, proactively coordinating engineering and construction aspects, as well as procurement aspects, of the PO. High-level priorities were shared with the fabricator, but, in contrast to Project A, project systems were integrated with the fabricator. The project team was able to deliver priorities at the spool level directly into the fabricator's system. Project B received the finer granularity of takeoff at the spool level (which the project's engineering team was unable to do) and included the fabricator's receipt data, capturing UOS&Ds in the project materials management system. As a result, instead of being forced to rely on the fabricator's cascade allocation system to release spools into fabrication, Project B utilized the project's sophisticated construction priorities materials management tool and specifically directed the fabrication of each spool. As a result, not only did Project B's spool fabrication go smoother, but so did its downstream piping erection program.

Fabricators generally utilize a cascade allocation system, designed to get as many spools as possible into fabrication. While this approach can achieve the intended goal, it does so to the detriment of individual spool delivery priorities.

TABLE 1 depicts the differing delivery sequence for two identical spools. The first path is via a cascade system, which does not hold inventory for otherwise non-releasable spools if that inventory can be used to put a lower-priority spool into fabrication. The second path is through a priorities system that reserves inventory for spools by priority, even if the spool has other materials not available. The cascade system will get more spools delivered sooner; however, these spools tend to be the wrong ones. **TABLE 1** shows that, for the two spools in question, while the cascade system has an enhanced delivery curve, it gets one spool to the jobsite too early, and the other spool arrives there too late. In contrast, while the priorities system has a delayed delivery curve relative to the cascade system, this system gets the spools to the jobsite when they are needed. The cascade system not only negatively impacts erection, but it also requires the jobsite's warehousing team to unnecessarily store and manage spools. Multiply this by 10,000 for a project with 20,000 spools and the ensuing chaos is obvious.

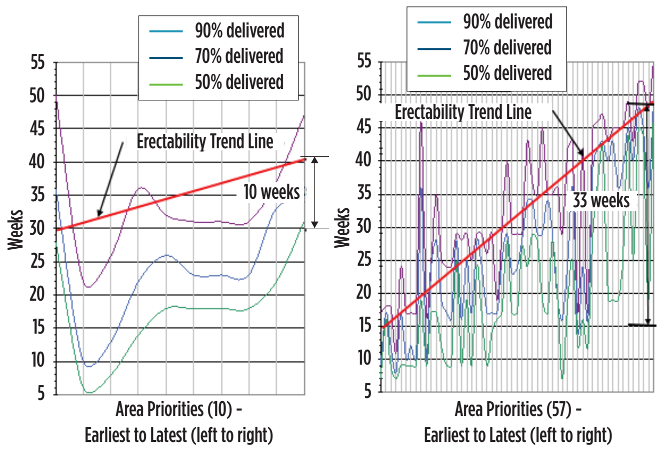


FIG. 3. Pipe spool delivery curves: Project A (left) vs. Project B (right).

Project A's early delivery curves were not grounded in hard data, but on the fabricator working to project priorities. Spools were cannibalized by the fabricator's cascade system as the fabrication process proceeded, causing the curves to slip more than 6 mos to the right. Project B's curves were initially less optimistic, but, as they were grounded on hard data from the integration, they proved to be more accurate. Project B's actual delivery curve never slipped outside of a +/– 10% delivery time frame. **FIG. 3** shows flat spool delivery on Project A, relative to actual construction priorities, as opposed to the far steeper and more desirable curve on Project B.

Project A communicated only 10 priorities to the fabricator and allowed the fabricator to release spools into fabrication, utilizing the fabricator's cascade allocation process. The net effect was that the first priority area achieved erectability (i.e., the level of spool deliveries at the jobsite necessary to support the start of erection) 30 wk after deliveries began. The last priority area achieved erectability at 40 wk—only 10 wk after the first priority. This delayed the start of pipe spool erection at the jobsite and created an undesirable peak in resource staffing.

Project B communicated 57 priorities to the fabricator, integrated the fabricator's enterprise resource planning system with Project B's materials management tool, and directed the fabricator to release spools into fabrication on an individual spool basis by using Project B's materials management tool. The net effect was that the first priority area achieved erectability 15 wk after deliveries began. The last priority achieved erectability at 48 wk, a 33-wk difference. This facilitated an early pipe spool erec-

tion time frame and allowed staff resources to avoid an undesirable peak. Additionally, on Project A, UOS&Ds took a back seat to production concerns and were not addressed upon receipt. Not only did the project lose the opportunity to have the component supplier correct the cause of the UOS&Ds, but Project A was caught off guard late in the project when the scope of the issue came to light. For spool components, particularly when it is a supplier's market, UOS&Ds can easily approach 5% or more. This not only significantly impacted individual spool constructability on Project A (where only a single insignificant component will block release to the floor), but it left the project team unaware of a significant unsourced scope, thus cutting into contingencies and delaying construction.

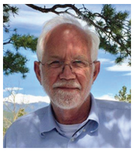
In contrast, Project B immediately addressed UOS&D data that was fed directly back into the project materials management system via integration. This allowed Project B to actively correct the UOS&Ds as they occurred and to avoid surprises late in the pipe spool fabrication program.

Finally, and of no small significance, the integration on Project B fostered high levels of communication and cooperation that were not evident on Project A. This mitigated any acrimony that could have occurred in the collaboration effort between an EPC contractor and a significant supplier if communication had not been good and expectations had not been met.

Takeaway. In the first example, a seemingly minor and well-intended, but misinformed, change had a disastrous impact on construction. Downstream impacts like this example occur routinely when projects do not have a cross-functional materials-related team in place to watch for these minor transgressions. Unfortunately, when this type of team is not present, these transgressions are often swept under the proverbial rug and accepted as the cost of doing business. However, these transgressions will not occur if the EPC organization implements an optimal approach to materials management.

In the second example, utilizing a cross-functional materials-related team (as opposed to a silo-based procurement team) to manage complex cross-functional activities significantly enhanced project execution.

Part 2 will review how barriers created in a document-centric execution are transitioning to a data-centric execution and will also discuss how implementing an optimal materials management effort, along with a cross-functional materials-related work process, can lead the transition to data-centric execution and significantly enhance productivity. HP



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CCR heater convection section bottom tubesheet design improvements

Continuous catalytic reforming (CCR) is a general reforming process used in the petroleum refining industry. The process fired heater plays an important role in this process. Fired heaters consist of heat transfer, convection and radiation coils. The radiant section is typically used for process heating, while the convection section is typically used for heat recovery and steam generation. Convection coils have horizontal tubes that are supported on refractory-lined end tubesheets (plated construction) and cast intermediate tubesheets.

In the typical installation of a CCR heater convection bottom section, multiple cast intermediate tubesheets are used to support coil banks. The bottom tubesheet that supports steam generation and/or steam superheating coils is exposed to high-temperature flue gases coming from the radiant section. Simultaneously, the tubesheet is cooled by the heat transfer tubes through which boiler feed/steam generation/steam super heating takes place. Therefore, the CCR convection bottom tubesheets are exposed to severe thermal gradients (flue gas side-to-process side temperature variations). Cast intermediate tubesheet flanges and web ligaments (material between tube holes) experienced loading (e.g., thermal expansion) due to high temperatures, frictional force between the tubes and the tube holes, and the dead weight of the tubes.

In one of the fired heater installations, the cast intermediate tubesheet in the CCR heater developed cracks in the web ligaments and flanges of the bottom tube row, leading to failure of the tubesheet and frequent replacements. In this article, finite element analysis (FEA) root cause analysis of the failed tubesheet and the countermeasures adopted in an improved new tubesheet design are explained in detail. The findings are beneficial to CCR process licensors, fired heater designers/suppliers and end users/customers in the petroleum refining industry.

Process fired heater configuration. A process fired heater (i.e., furnace) is a heat transfer-type of equipment that plays an integral role in the petroleum refining, petrochemicals, fertilizers and chemicals industries. It consists of a furnace box, heat transfer coils, coil supports and a flue gas passage. **FIG. 1** shows the configuration of a typical CCR fired heater. **FIG. 2** shows a typical convection coil bottom tubesheet geometric model used for FEA. Fuel gas, fuel oil, or oil and gas is fired in the heater through burners, and the generated heat is transferred to the fluid circulating through coils placed near heater walls and in the flue gas passage.

Though this study covers typical CCR fired heater convection bottom tubesheets, the results and outcome can be extended to other types of fired heaters/furnace configurations. The point of concern for cast tubesheets used in convection bottom coils is tubesheet exposure to very high flue gas temperatures and large thermal gradients present from the coil side (e.g., steam service or other service coils).

Conventional tubesheet design. A typical conventional intermediate tubesheet used in a CCR heater convection bottom section is shown in **FIG. 2.** The tubesheet is manufactured by a static casting process. In this study, the tubesheet geom-

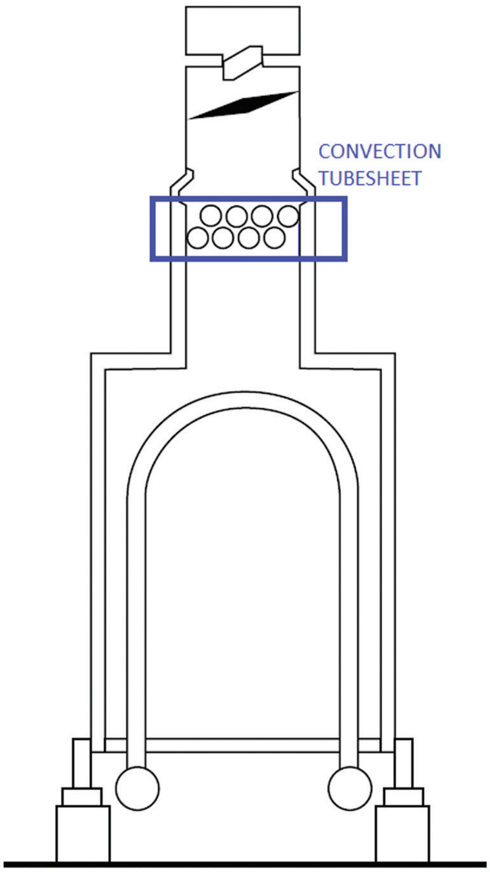


FIG. 1. Typical CCR fired heater configuration.

etry used is shown in **FIG. 2.** It has four tube rows (the bottom three shock rows have bare tubes and a fourth row from the bottom has studded tubes), with circular holes for tube placement. Below each tube row's flanges are support for the tubes passing through the holes. The tubesheet is supported from the ends at the support location placed above the first tube row. The CCR fired heater—where these tubesheets are installed—uses oil and gas in combination as fuel. The tubesheet material used in this design—ASTM A560 Gr. 50Cr-50Ni-Cb—recommended using fuel oil for firing. The improved design—A297 Gr. HP Mod (25Cr-35Ni-Nb)—recommended fuel gas for firing, which was being used at the customer's facility. The HP Mod material has better creep-rupture strength and better thermal shock resistance.

TABLE 1. Material properties for ASTM A560, Grade 50Cr-50Ni-Nb

Temperature, °C	Young's modulus, GPa	Poisson's ratio	Coefficient of thermal expansion, mm/mm°C * 10^{-6}
800	124		18.3
725	137		18
667	143.96	0.3	17.8
614	149.6		17.6
590	150		17.5
550	156		17.3

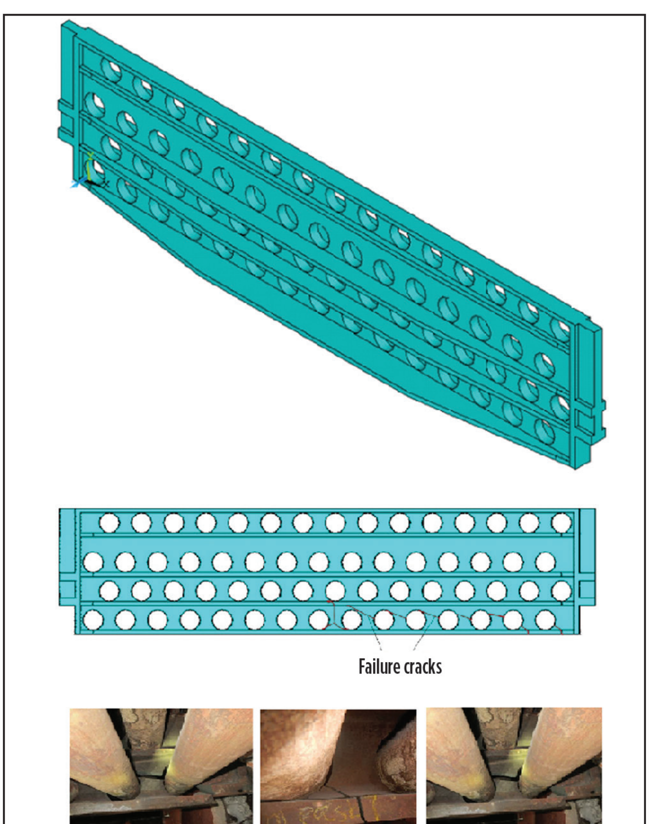


FIG. 2. Configuration of the tubesheets and locations of cracks.

Tubesheet failure. In the convection bottom cast intermediate tubesheets within one of the fired heater installations, cracks were repeatedly found in the tubesheet web ligaments of the first tube row from the bottom, as well as in the first tube row's bottom flange. Typical crack locations in the tubesheet are shown in **FIG. 2.** After replacing the tubesheets with a similar design, repetitive cracks were found in the installation, which led to repeated shutdowns for repair and replacement and loss of production time.

The following are the design factors and probable causes of failure of the tubesheet:

- Dead weight of the tubes and the tubesheet
- Friction between the tube hole and the tube, and friction between the tubesheet support and resting surfaces
- Thermal expansion of the tubesheet in the direction of its length and the relative position of the tubes

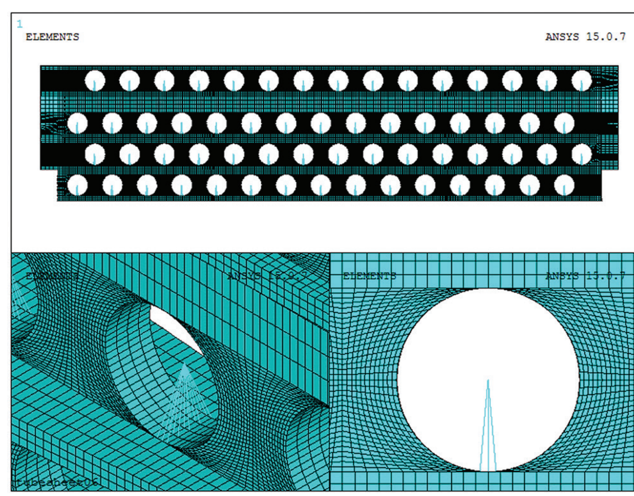


FIG. 3. FEA model.

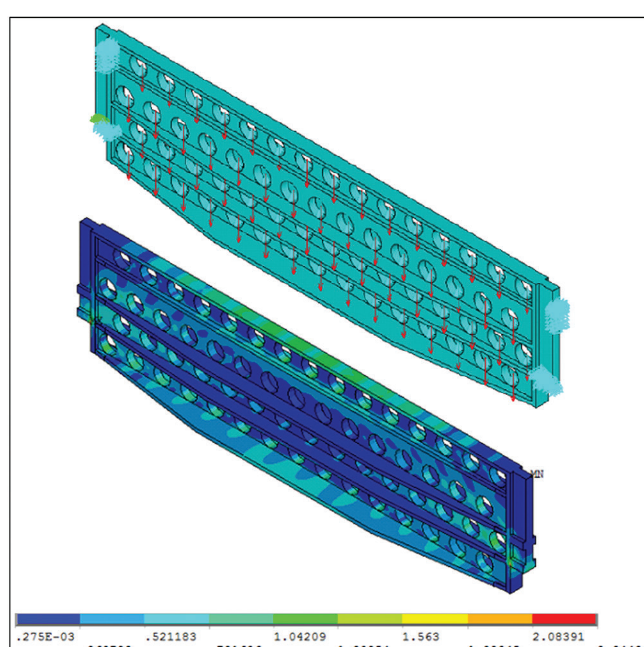


FIG. 4. Dead weight load case.

- Large temperature gradient in the ligaments of the tube sheet
- Differential thermal expansion between the coils (connected to the header) and the tubesheet
- Bracket support location above the bottom tube row
- Flow-induced vibration of the tubes due to the internal two-phased fluid flow
- Tube-sheet material behavior during temperature changes and thermal shocks.

FEA. A detailed FEA was performed to simulate each possible cause of failure. The following are the details of the FEA:

- The model consists of the tubesheet, supporting arrangement, tube holes and support flanges. A 3D thermal solid elements (SOLID70) are used for thermal analysis. A structural 3D eight-noded solid elements (i.e., SOLID185) are used for the FEA model.
- Tube holes are considered rigid for dead weight and friction load was caused by using multi-point constraint 3D rigid beam elements (i.e., MPC184).
- The FEA model used for analysis is shown in **FIG. 3.**
- The composition of the tubesheet is 50Cr-50Ni.
- The FEA model was checked for element shape and mesh sensitivity.
- The FEA model was tested for aspect ratio, parallel deviation, maximum angle, the Jacobian ratio and the Warping factor.
- The number of elements was 177,952 (SOLID185 was 174,232 elements and MPC184 was 3,720 elements).
- The material properties used for ASTM A560, Grade 50Cr-50Ni-Nb are shown in **TABLE 1.**

As per ASME Sec. VIII Div.2 Part-5, the allowable limit on the primary and secondary stress range (S_{PS}) is three times the average of the *S* values for the material from ASME Sec. II Part D Table 5A at the highest and lowest temperatures during the operational cycle. In this case, the allowable stress limit for primary and secondary stresses was 343MPa.

From the probable causes of failure, the following load cases were considered for the FEA simulation:

- Dead weight of the tubesheet
- Friction between the tubes and the tubesheet holes
- Thermal expansion of the tubesheet and the tubes in fixed position.

Dead weight of the tubesheet. FEA was performed to calculate stresses subject to the dead weight of the tubesheet and the dead weight of the tube coil. Load application details are shown in **FIG. 4.** As shown in **FIG. 4,** the calculated stresses are negligible in the ligaments; therefore, the dead weight of the tubesheet will not be the cause of the tubesheet's failure.

Friction between the tubes and the tubesheet holes. Coil tubes are rested at the tubesheet holes. During operations, the axial expansion of the tubes causes friction between the tubesheet holes and the tubes. Load application details are shown in **FIG. 5.** Another location of friction will be at the tubesheet's rest position. A frictional load of 30% dead weight was applied for the tube and tubesheet rest locations. The stress level due to frictional force did not result in ligament failure.

Thermal expansion of the tubesheet. Along the height of the tubesheet (approximately 800 mm in this case study), the temperature drops 200°C through heat transfer. In turn, this shows a very high temperature gradient in the ligament section of

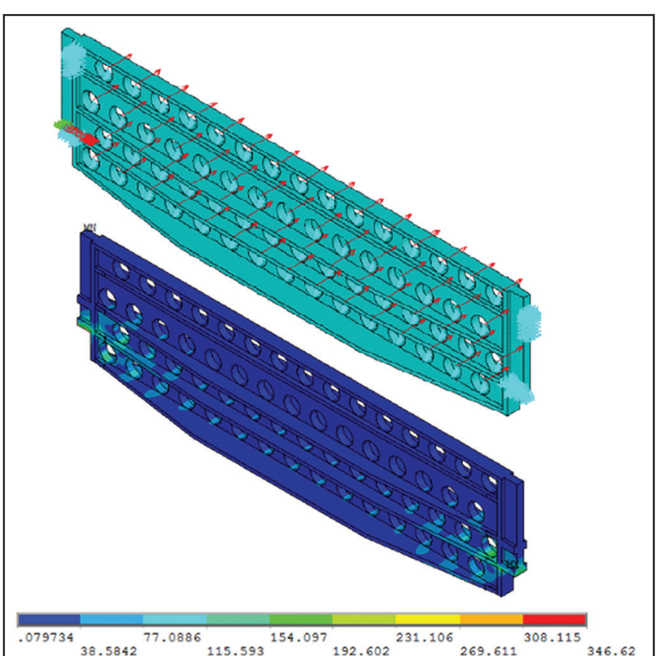


FIG. 5. Tube-to-tube hole friction load case.

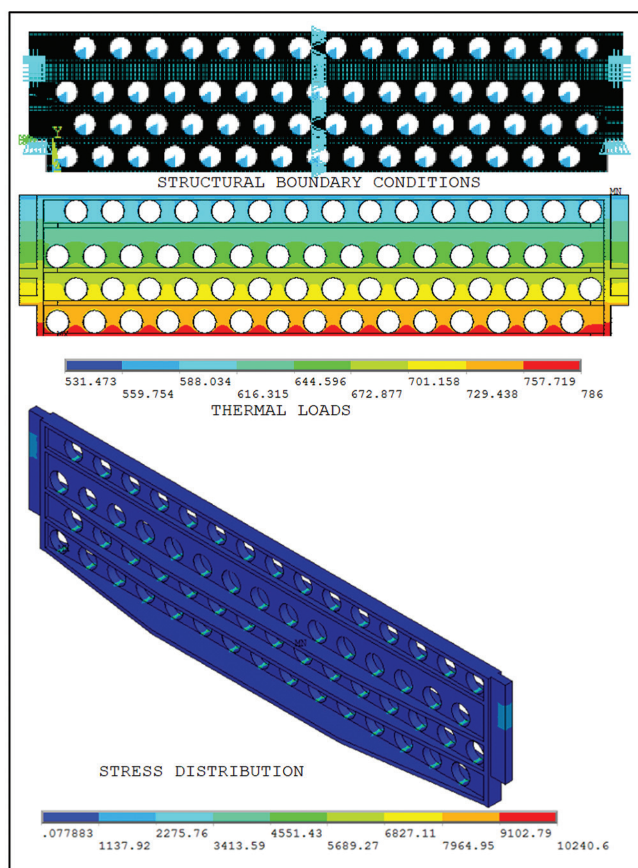
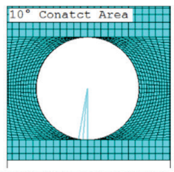
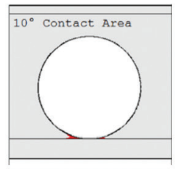
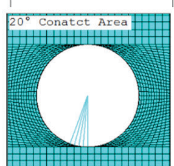
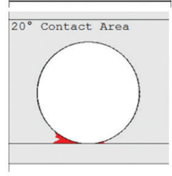
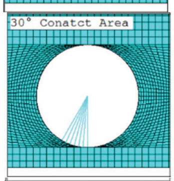
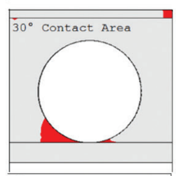
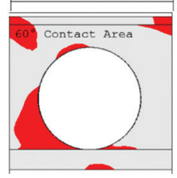
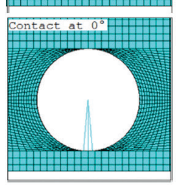
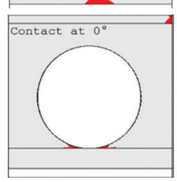
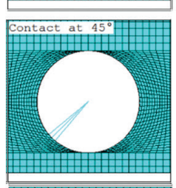
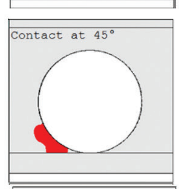
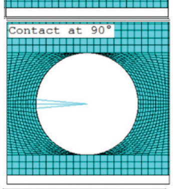
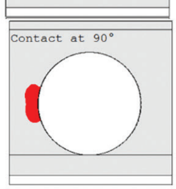
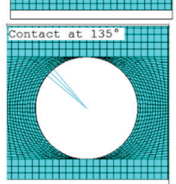
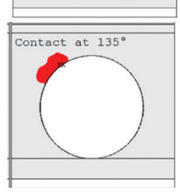


FIG. 6. Thermal expansion of the tubesheet load case.

TABLE 2. Overstress plot points near the tube contact location

Case	Contact angle, °	FEA model at the tube hole	Overstress region
1	0–10		
2	0–20		
3	0–30		
4	0–60		
5	-5–5		
6	40–50		
7	85–95		
8	130–140		

the bottom row of the tubesheet (**FIG. 6**). The high temperature causes a higher expansion of the bottom row than in any other parts of the tubesheet. At elevated temperatures, allowable stress values are reduced and cause overstress in the ligaments—the ambient temperature considered for the FEA analysis was 35°C.

To check for the possibility of tubesheet failure due to expansion, tubesheet expansion with various tube rest locations in the tubesheet hole was simulated. For a conservative scenario, the tube positions were fixed. When the tubesheet expands, the tube will exert force on the ligament between the tube holes as the tube tries stay in a straight position. This load case simulated keeping the tube center line fixed by applying MPC184 elements. The calculated stresses were very high, which may have caused the tubesheet failure.

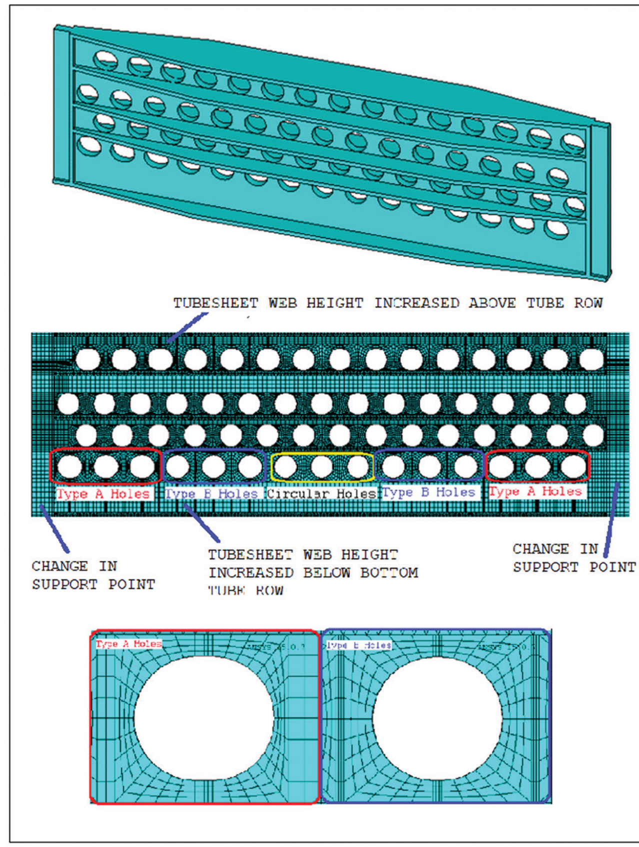


FIG. 7. New design changes in the tubesheet holes.

Tubesheet coils at the end of the tubesheets (plated construction with refractory) have fixed connections, while the intermediate tubesheet coils are only supported (rested) and free to move in the tubesheet holes. This causes relative thermal expansion/displacement of the tubes during heater startups, ramp-ups and shutdowns.

The tubesheet is supported above the first tube row. During thermal expansion, there is sufficient clearance for thermal expansion, which will not cause stress concentration near the support point location. In addition, during axial movement of the tubes, the bottom tube row acts as a cantilever and bending stresses occur in the bottom tube row ligaments.

The heater bottom tubesheet has convection coils that carry two-phase fluid, which causes flow-induced vibrations during operations, especially during initial startups. Simulations for these loads were performed and found that the stresses are negligible and cannot play a major role in the tubesheet failure.

Case study. Tubesheet expansion in the direction of its length and the relative position of the tubes may be the reason for failure. A case study was performed for various tube resting positions—as might have happened during initial heater construction and subsequent tubesheet/coil replacement and/or also

in operation due to coil/connecting coil header and tubesheet relative thermal movements—and the effect in the ligaments.

For case study purposes, a FEA model was conducted with a contact area between the tubes and the tubesheet holes at 10°, 20°, 30° and 60°, with four different models. This phenomenon is captured in the FEA by connecting the tube center point and the tube hole nodes in the vicinity of the contact area by using multi-point constraint elements. Cases 1–4 in **TABLE 2** show the contact area of 10°, 20°, 30° and 60° between the tube hole and the tubes. As the contact area increases, the overstressed area near the ligament also increases.

A case study was also performed on the tube's resting position in the tube hole, with a contact angle of 10°. The study was performed with tube rest locations at 0°, 45°, 90°, 135° and 180°. Cases 5–8 in **TABLE 2** show the various tube contact points in the tube hole and the stress distribution during thermal expansion for various contact areas. From the stress distribution pattern, as the contact area increases, stresses in the ligaments increased, as well.

Stress distribution during thermal expansion for various contact angles is also shown in **TABLE 2.** From the stress distribution pattern, the overstressed region in the tubesheet will vary in line with the contacting location of the tube. If the contact takes place in the ligament and not at 0° or 180°, overstress is higher.

New design. From the detailed FEA and case study, a new tubesheet design was completed (**FIG. 7**). The following design improvements were incorporated:

- The shape of the tubesheet's holes were changed from circular to slotted to allow the free movement of the tubesheet and coil terminal headers during thermal expansion; therefore, the tubes will not exert lateral forces on the tubesheet's web ligaments.
- In the bottom tube row, the ligaments between the tube holes in the tubesheet experience a very high temperature gradient. To avoid this, the tubesheet flange height below the bottom tube row and above the top row were increased.
- In the original installation, the tubesheet support location was above the first tube row. Considering thermal expansion, to ensure that the tube rests within the tubesheet during operation, the support location was shifted to below the first tube row bottom flange.
- The materials composition of the tubesheet was changed to 25Cr-35Ni-Nb (A297 HP Mod) since it has high strength at elevated temperatures.

The new design was simulated for the following load conditions:

1. Temperature load
2. Dead weight
3. Friction load.

During thermal expansion, the tube's position in the tube hole did not exert force on the ligaments due to the tubesheet hole's slotted shape change, which allowed for free movement of the tubesheet and coil headers/tubes. Therefore, an analysis was not performed for this load.

FIG. 8 shows temperature distribution in the tubesheet and in the bottom tube row ligaments. In the new design, thermal gradient across the ligament is lower vs. the original design. Stresses in the tubesheet are within allowable limits, as well.

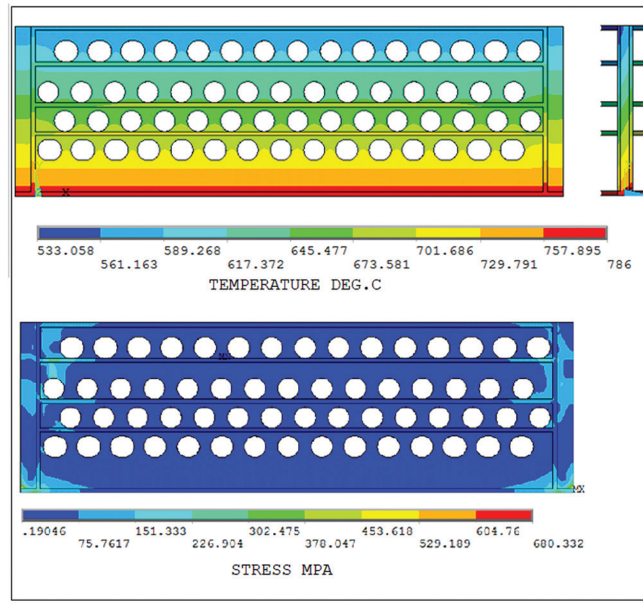


FIG. 8. Stress distribution in the new design.

Takeaways. The probable causes of failure in cast intermediate tubesheets within a CCR heater were investigated.It was found that insufficient space for coil thermal expansion/displacement in the tube holes and a large temperature gradient in the bottom row ligaments were the major causes of tubesheet web and flange cracks, which led to the tubesheet failures.

A new design of the tubesheet was proposed to overcome the limitations in the initial design. The new design was simulated by FEA and found suitable for the intended design and loading conditions.

The new tubesheet design was implemented in one of the CCR heater installations as part of a heater revamp. All convection bottom coil bank cast tubesheets were replaced. The CCR heater, with the new cast tubesheet design, has operated efficiently for the past 2 yr, with no cracks. HP

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Advanced methods for controlling boiler tube corrosion and fouling—Part 1

Many heavy industrial plants, such as refineries and petrochemical facilities, require steam for numerous processes, including powering turbines, providing energy for a variety of unit operations and even heating buildings in some locations. However, as the authors and their colleagues have frequently observed, steam generators and their auxiliary systems are often not given the same attention as other plant processes. Only after failures occur do plant personnel begin to understand the importance of reliable makeup water preparation, impurity control in boiler feedwater and condensate return, and careful selection of internal boiler water treatment programs.

Common boiler corrosion and failure mechanisms include tube overheating, caustic gouging, acid phosphate corrosion and hydrogen damage, all of which are accentuated and often initiated by boiler tube deposits. Deposition can be problematic in both direct-fired and waste heat boilers. As an example of the latter, this article includes a discussion of corrosion in olefins plant transfer line exchangers (TLEs), which quench cracked hydrocarbons and generate steam in the process.

Part 1 of this two-part article series focuses on condensate return and feedwater corrosion protection, as corrosion products from these locations are often the most troublesome impurities that can reach the boilers.

A core principle: Minimizing deposit formation. For steam generators in virtually all industries, a core principle for boiler protection is minimizing deposit formation in boiler tubes and other internals. Even with seemingly proper boiler water chemistry control, deposits can influence and enhance reactions at the tube surface to generate corrosive compounds. Corrosive and deposit-forming compounds and corrosion products may be introduced to steam generators via a variety of pathways. The most prominent pathways are:

- Inadequate feedwater and condensate return chemical treatment
- Upsets in makeup water treatment systems that allow impurities to enter boiler feedwater
  - The flip side to this issue is a modification in makeup water treatment that may solve some problems but introduce others
- Cooling water in-leakage from a steam condenser or other water-cooled heat exchanger into condensate
- Process chemical leaks into condensate return.

A definite purpose lies behind the order of this list, as the first two issues may accentuate the following two. Examples follow.

Corrosion control in condensate/feedwater systems. Since the advent of steam use for industrial purposes, and as boiler pressures and temperatures increased with evolving technology, a key focus has been condensate/feedwater system corrosion, transport of corrosion products to boilers, and the effects of deposition on boiler corrosion and heat transfer.

Carbon steel is the primary material for most condensate and feedwater systems. A large facility may have many miles of carbon steel piping and other equipment. Common corrosive agents in these systems are dissolved oxygen (DO) and carbonic acid, which damage material and release iron oxide to the condensate (**FIG. 1** and **FIG. 2**).

Even with good chemistry control, some carbon steel corrosion will occur. The majority of corrosion products, generally over 90%, exist as iron oxide particulates that will travel to the boiler without some form of filtration. The products then deposit on the boiler tubes, usually on the hot side. Reduced heat transfer is one difficulty with iron oxide deposition, and it leads to increased costs for fuel firing. Tube overheating is potentially much more troublesome (**FIG. 3**).

Adding to these difficulties is the porous nature of iron oxide particulates,

FIG. 1. Oxygen attack of a carbon steel feedwater line.

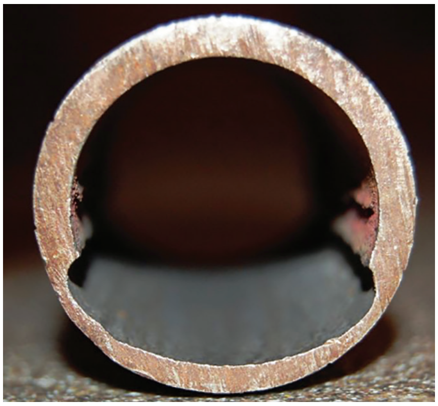


FIG. 2. Carbonic acid grooving in a condensate return pipe.

which allow water to penetrate through various channels. As the water approaches the tube surface, temperatures increase. The water boils off, leaving other species behind. This phenomenon is known as wick boiling (**FIG. 4**).

Boiler water impurities, including treatment chemicals, can concentrate many times at the tube surface and induce corrosion (sometimes severe) that may lead to rapid boiler tube failures. A common reaction in boilers subject to contaminant ingress is shown in Eq. 1:

$$MgCl_2 + 2H_2O \rightarrow Mg(OH)_2\downarrow + 2HCl \quad (1)$$

One product of this reaction is hydrochloric acid (HCl). While HCl can cause general corrosion in and of itself, the compound will concentrate under deposits where reaction of the acid with iron generates hydrogen, which in turn can lead to hydrogen damage in the tubes. In this mechanism, atomic hydrogen penetrates into the steel and reacts with carbon atoms to generate methane (CH_4), as shown in Eq. 2:

$$4H + Fe_3C \rightarrow 3Fe + CH_4\uparrow \quad (2)$$

Gaseous methane and hydrogen molecule formation induces cracking, greatly weakening the steel's strength. Hydrogen damage is troublesome because it cannot be easily detected. After hydrogen damage has occurred, the plant staff may replace tubes only to find that other tubes continue to rupture (**FIG. 5**).

One may consider an important twist to this example. As will be discussed later, sodium phosphate compounds, and sometimes even straight caustic (NaOH), are added to boiler water to maintain alkalinity and minimize general corrosion. However, under heavy deposits, sodium hydroxide concentrations can rise to much higher levels than in the bulk boiler water. The concentrated NaOH attacks the boiler metal and protective magnetite film via the following reactions, shown in Eqs. 3 and 4:

$$Fe + 2NaOH \rightarrow Na_2FeO_2 + H_2\uparrow \quad (3)$$

$$Fe_3O_4 + 4NaOH \rightarrow 2NaFeO_2 + Na_2FeO_2 + 2H_2O \quad (4)$$

The upshot of these examples is that chemistry throughout the steam generation system requires careful control to minimize corrosion and corrosion product transport. Modern methods for this purpose are examined in the next section.

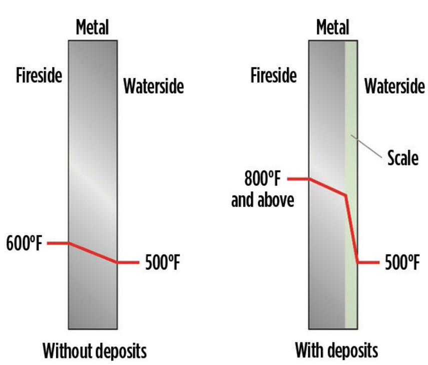


FIG. 3. Influence of deposits on boiler tube wall temperatures. The increase in wall temperature can degrade metal integrity and lead to premature failures from metal deformation.

FIG. 4. An illustration of wick boiling.

FIG. 5. Hydrogen damage. Note the thick-lipped failure with little metal loss from direct corrosion.

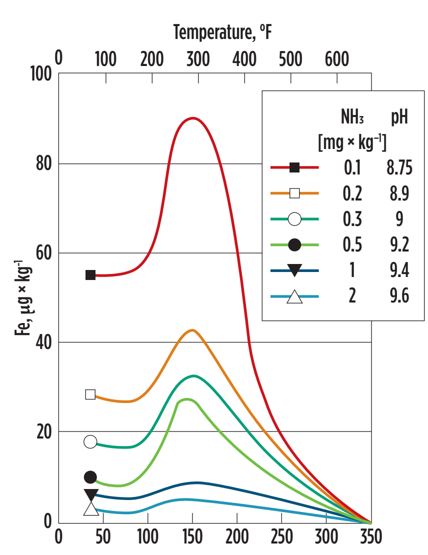


FIG. 6. Influence of temperature and pH on iron dissolution from carbon steel.[1]

Feedwater and condensate return system protection. A critical requirement for steam generating systems is proper pH control to minimize general corrosion. An extremely informative graph of the effects of pH and temperature on carbon steel corrosion was prepared a half century ago and is shown in **FIG. 6.**

This research was conducted in high-purity water samples. A key aspect of this chart is the influence of pH on carbon steel corrosion, which greatly decreases with pH elevation from 8.75 to 9.6. Note that the results were based on pH adjustment with ammonia (NH_3), the common feedwater pH-conditioning chemical for power plants, especially those with no copper alloys in the feedwater system. Ammonia raises the pH via the reaction shown in Eq. 5:

$$NH_3 + H_2O \leftrightarrow NH_4^+ + OH^- \quad (5)$$

Eq. 5 is an equilibrium reaction; therefore, the alkalinity increase is limited, minimizing excessive steel corrosion in the event of a chemical feed upset.

Complications arise in many industrial condensate systems as they have multiple metallurgies, often including copper alloy heat exchanger tubes. Ammonia and dissolved oxygen in combination are very corrosive to copper. Furthermore, the optimum pH range for general copper corrosion control is 8.8–9.1, somewhat lower than the pH range for carbon steel. In systems with both carbon steel and copper alloys, a balanced pH range of 9–9.3 is often recommended. Accordingly, for many industrial units, neutralizing amines may replace ammonia. Neutralizing amines are small-chain organic molecules with an ammonia group attached to or embedded within the compound (**FIG. 7**).

Some of the amines have a higher basicity than ammonia and can raise the pH to higher levels if necessary. Another important property of these chemicals is the distribution ratio—i.e., the amount of amine that carries over with steam vs. the amount that remains in the water. The ratios vary with boiler temperature and pressure, but some products tend to remain in the boiler water while others significantly partition with the steam. Careful selection of a blended product can provide comprehensive pH conditioning to the boilers, steam system and condensate return network.

Also important for condensate/feedwater treatment is choosing an oxygen

scavenger/metal passivation chemical. Industry-standard practice, especially in the power industry, had been to remove all dissolved oxygen from feedwater to minimize the corrosion shown in **FIG. 1** and protect copper alloys, if present. Accordingly, almost all steam-generating systems were equipped with a mechanical deaerator and oxygen scavengers/reducing agent feed systems. However, the last four decades have seen a number of high-pressure feedwater piping failures, some of which have caused fatalities.

Researchers have learned that the reducing environment produced by oxygen scavengers is the prime ingredient for single-phase, flow-accelerated corrosion (FAC) of carbon steel. The attack occurs at flow disturbances, such as elbows in feedwater piping and economizers, feedwater heater drains, locations downstream of valves and reducing fittings, attemperator piping, and, most notably for combined-cycle heat recovery steam generators (HRSGs), in low-pressure evaporators, where the waterwall tubes (i.e., harps) have many short-radius elbows. These locations correspond to the temperature influence shown in **FIG. 5.** Single-phase FAC has an orange-peel texture, as shown in **FIG. 8.**

Gradual metal loss occurs at FAC locations until the pipe wall in the affected zone can no longer withstand the fluid pressure. Sudden failure is the result, accompanied by the release of high-temperature water (**FIG. 9**).

The combination of ammonia or neutralizing amine feed, along with one of the volatile oxygen scavengers/reducing agents described previously, is known in the power industry as all-volatile treatment reducing [AVT(R)].

European and Russian facilities began moving away from AVT(R) in power units in the late 1960s and early 1970s. Researchers and chemists at supercritical power

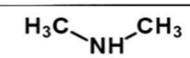
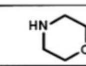
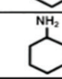
Amine	Chemical Formula	Molecular Weight (g/mol)	Structure
Dimethylamine	C_2H_7N	45.08	
Ethanolamine	C_2H_7NO	61.08	
5-Aminopentanol	$C_5H_{13}NO$	103.16	
3-Methoxypropylamine	$C_4H_{11}NO$	89.14	
Morpholine	C_4H_9NO	87.1	
Cyclohexylamine	$C_6H_{11}NH_2$	99.2	

FIG. 7. Common neutralizing amines.

plants discovered that in high-purity feedwater (cation conductivity ≤ 0.15 μS), the deliberate injection of a small amount of oxygen (to establish a DO concentration of 50 ppb–300 ppb) and elimination of oxygen scavenger feed would cause the grayish-black magnetite (Fe_3O_4) layer on carbon steel surfaces to become interspersed and overlaid with a different oxide layer, known variously as α-hematite and ferric oxide hydrate. With rigorously maintained chemistry, this oxide forms a much tighter bond than magnetite and greatly minimizes FAC. The program gained the name of oxygenated treatment (OT) and was adapted as the replacement for AVT(R) at many supercritical units around the world, although it is unacceptable for units with copper-alloy tubed feedwater heaters, as the combination of oxygen and ammonia will cause severe copper alloy corrosion.

Subsequently, the Electric Power Research Institute (EPRI) developed a program to replace AVT(R) for drum units with AVT(O), which stands for all-volatile treatment oxidizing. If the condensate/feedwater system contains no copper alloys (which is true for virtually all modern HRSGs), then AVT(R) is *not* recommended. In brief, with AVT(O) chemistry, as with OT, the oxygen scavenger feed is eliminated. A small residual concentration (5 ppb–10 ppb) of dissolved oxygen is required at the economizer inlet. Ammonia or an ammonia/neutralizing amine blend is still utilized for pH control. High-purity condensate (cation conductivity ≤ 0.2 μS/cm) is required for AVT(O), but when proper conditions are established, the magnetite becomes overlaid and interspersed with the tighter-bonding α-hematite. The layer is noticeable for its distinct red color (**FIG. 10**).

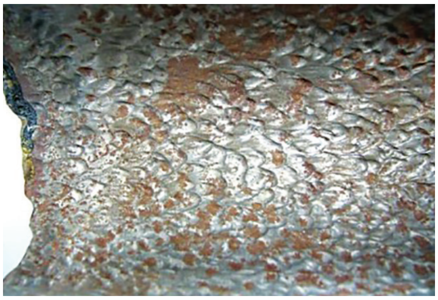


FIG. 8. Surface view of single-phase FAC. Note the orange-peel texture.

FIG. 9. Photo of tube wall thinning caused by single-phase FAC.

OT and AVT(O) have proven so successful that the major power chemistry research organizations strongly recommend the elimination of oxygen scavengers in all power steam generators unless the feedwater system contains copper alloys.

However, AVT(O) and OT often cannot be employed at industrial plants because the feedwater does not meet the purity limits previously listed. Dissolved oxygen would cause serious carbon steel corrosion. Also, many industrial heat exchangers have copper alloy tubes, which, as has been noted, can suffer serious attack from the combination of ammonia (including ammonia generated by neutralizing amine decomposition) and oxygen. Amine/oxygen scavenger treatment is required in these cases to minimize corrosion.

This issue and others must be factored into the selection and monitoring of condensate/feedwater treatment programs, including those at industrial plants that have switched to high-purity makeup systems but still see impurity ingress from the condensate return.

Formerly, sodium softening to remove hardness was the primary treatment method at many industrial plants. This fundamental technique had both advantages and disadvantages, with low cost being a primary benefit. However, softening system upsets or inadequate effluent monitoring may cause severe boiler tube scaling, as the authors and their colleagues have observed at many facilities. A dramatic example is shown in **FIG. 11.**

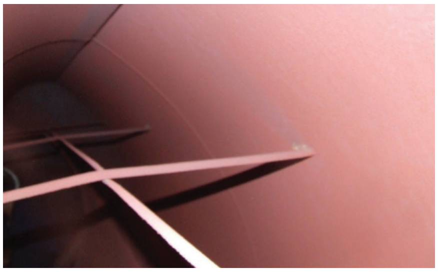


FIG. 10. Properly passivated surfaces in a unit on AVT(O). Photo courtesy of Dan Dixon, Lincoln Electric System.

In many cases, notably at refineries and similar industrial facilities with high-pressure boilers, the modern makeup arrangement is reverse osmosis (RO), perhaps followed by ion exchange (IX) demineralization. However, at any plant where a change is made from softened to higher-purity water, careful evaluation of feedwater treatment chemistry is recommended. Simple sodium-softened water still contains the alkalinity from the raw supply. This alkalinity can help protect the feedwater piping. Without feedwater treatment modifications, a change to high-purity water may lead to the corrosion issues noted previously, including FAC.

Continuing evolution of film-forming products. Research and development continues to improve film-forming products (both amine-based and those based on other compounds with alternative active groups) for steam system metal protection. Decades ago, filming amine chemistry was applied to steam generators, with a common compound being octadecylamine (ODA, $C_{18}H_{39}N$). The amine group attaches to the metal surface, and the hydrophobic organic "tail" extends into the fluid to shield the metal (**FIG. 12**).

However, poor control and lack of knowledge often lead to problems with ODA applications, including formation of gelatinous spheroids, or "gunk balls" in the common vernacular, which fouled steam generators. More advanced amine and non-amine film-forming products (FFP) have been developed. Most of these operate best in mildly basic conditions, so neutralizing amine treatment is still necessary. Product feed is based on the residual concentration that best protects metal surfaces. Regular iron monitoring can be very important in evaluating and fine-tuning programs. Some products will actually cause dissolution of porous iron oxide deposits during initial application, which can sometimes be falsely assumed as base metal corrosion.

Much of the effort to date has been concentrated in the power industry, and literature[2] provides details of a recent successful case study of a film-forming amine (FFA) application. This chemistry is also expanding into the refining and petrochemical industries. Successful products provide true corrosion inhibition by forming a chemi-

cal barrier on the metal surface. They do not offer a panacea for poor chemistry control; however, they do offer strong potential for comprehensive steam generator corrosion protection. The authors hope to provide more details in the near future with an article devoted to this technology.

With the wide variety of intermediate and final products generated at industrial plants, the possibilities for contaminant leakage into condensate return are enormous. Impurities may include complex organics, strongly acidic or basic compounds, mineral salts and many others.

One way to minimize impurity transport to boilers is by equipping the condensate return system with a dump line so that an excursion shown by instrument readings (e.g., specific conductivity) will open a valve and allow the condensate to be drained rather than returned to the steam generators. Some plants employ total organic carbon (TOC) analyzers to monitor return condensate. If neutralizing amines are utilized for pH adjustment, the contributing TOC from the amine is taken into consideration, and a target TOC is selected for dumping. Dumping can involve a large loss of water and may require special makeup water system design to handle periodic high makeup requirements. An alternative idea—albeit one that requires additional funding and staffing—is to place a condensate polisher on the return line to the boilers. The choice of equipment and polishing process will depend on the impurities to be removed and mechanical conditions such as flowrate, temperature and pressure, but a number of options are available, including:

- Ion exchange resins, with some flexibility of selection for particular contaminants
- Particulate removal by fabric or mechanical filters.

Ion exchange resins can be specifically designed to remove a variety of dissolved ions, ranging from primary cations and anions to other trace constituents. However, some resins may be limited by temperature, as some anion resins begin to break down at temperatures not much higher than 100°F.

Direct filtration is a straightforward technique, particularly if system corrosion generates a significant amount of iron oxide or other metal particulates. A prime example comes from the power industry, where air-cooled condensers (ACC) are sometimes chosen as an alternative to cooling towers and water-cooled condensers for water conservation. ACC units require a huge amount of carbon steel piping to effectively cool turbine exhaust steam, and even with the best chemical treatment programs, the process still introduces a large amount of iron oxide particulates to the condensate.

Recommendations. Proper boiler protection starts with reliable makeup water system operation and good control over corrosion and impurity ingress in condensate return systems. Key principles include:

- Maintaining and controlling makeup systems to provide consistent effluent. Upsets can send many scale-forming or corrosive ions and compounds to the boiler, including hardness, aggressive anions and silica.
- Controlling chemistry consistently for unit protection. While consistent makeup water quality is important, many impurities and corrosion products can enter the condensate return from leaking condensers and process heat exchangers. Condensate return dumping and polishing methods are available for mitigating these difficulties.
- Monitoring systems consistently. The importance of monitoring cannot be overstated. Upsets have been known to cause boiler tube failures within days, and sometimes even hours. Continuous online instruments are available for complete steam generation chemistry monitoring. Intelligent water management software is also available for tracking and analyzing data and providing reports and alarm notices to plant personnel. This program is also well-suited for monitoring other plant water systems, including cooling water.

All systems are different. Like all technologies, due diligence is necessary to determine the feasibility for utilizing these methods. Equipment manuals and guides should always be consulted before making changes to systems and treatment processes. HP

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1. Sturla, P., Proc., Fifth National Feedwater Conference, 1973, Prague, Czechoslovakia.

FIG. 11. Severe calcium carbonate ($CaCO_3$) scaling in a low-pressure boiler tube. This is the same scale that appears in home hot water systems.

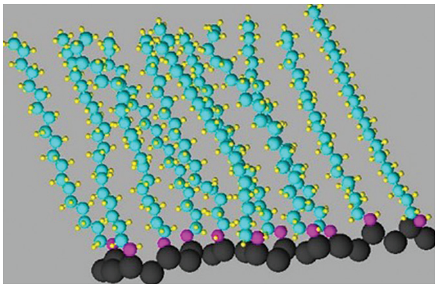

FIG. 12. General illustration of filming amine attachment to metal surfaces.[2]

2. Stuart, D., "Mitigating flow-accelerated corrosion with film-forming chemistry in HRSGs," *Power Engineering*, April 2021, online: www.power-eng.com

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Pump recycle line optimization and energy savings

The objective of this article is to demonstrate the benefits of optimizing the pumping system through pump recycle line evaluations. Excessive use of pump recycle lines can be a key indicator of pump oversizing—subsequently, hydraulic re-rating of the pump can result in significant energy savings. The focus of this article will be on detection and quantification of pump recycle line leakage or passing conditions. These efforts require very little effort and are considered low-hanging fruit, resulting in significant savings potential. This article includes a relevant case study related to recycle line leakage detection, along with the resulting energy and maintenance cost savings.

Pump recycle line. Energy conservation efforts are becoming an important area of focus for many industries that are looking to improve operating efficiency and profit margins. U.S. industry estimates indicate that approximately 20% or more of industrial electricity consumption is used by pumping systems; therefore, pumping systems are an ideal area of focus to realize energy conservation opportunities. This article discusses pumping system recycle or bypass system optimization.

There are two main purposes for a pump recycle line, and these include:

1. Protecting the pump from low-flow conditions, where, in this case, the recycle valve will open to maintain pump flow above minimum continuous stable flow
2. Facilitating pump startup and shutdown conditions, or hydraulic performance testing utilizing the recycle or bypass line.

Under normal operating conditions, the pump recycle valve should be closed. In some cases, the pump may operate with a continuous or frequent opening of the recycle valve. These conditions are a clear sign of pump oversizing, and they can be addressed by considering a hydraulic re-rate of the pump to better match actual system requirements. This article is concerned with a less-obvious pumping system deficiency, which is often overlooked, related to pump recycle valve leakage or passing conditions.

Typically, pump recycle lines do not incorporate a flow element (FE), which results in recycle valve passing conditions going undetected. These conditions can go undetected until the severity of the leakage either results in the inability to meet process flow demands or results in high noise and vibration levels. The objective of this article is to demonstrate the importance of human intervention and to ensure proper function of these systems. Valve passing conditions are often difficult to identify without a careful survey of these systems to detect passing valves. Typically, the flow element is upstream of the recycle line take-off; therefore, there is no flow indication to indicate any bypass control valve leakage.

Benefits. Very simple plant surveys can be conducted to evaluate shut-off integrity of these recycle valves to identify passing conditions and subsequent energy savings potential. At a minimum, these surveys should target higher energy pumping systems to realize the greatest benefit. Among the benefits of identifying passing recycle valve conditions are the following:

- Significant energy savings potential
- Reduced noise and vibration, since continuous leakage flow through recycle lines can induce vibration and noise
- Reduced maintenance costs, as passing valves will result in the erosion of valve seats, leading to reduced valve life and higher maintenance costs
- Excessive recycle valve leakage can result in the inability to meet process flow demand; in extreme cases, this may require operating an additional pump in parallel to meet system demand.

Methods of detection. When implementing pump recycle valve integrity surveys, there are three primary methodologies to consider:

- Differential temperature
- Acoustic emission (AE) or ultrasound measurements
- Portable ultrasonic flow measurement.

Differential temperature. If there is a large difference between process temperature and ambient temperature, then differential temperature across the recycle valve can be a good indicator of a passing condition. Different techniques can be utilized to detect the temperature differential, including the following:

- The easiest method is by feel or touch; however, care should be taken to avoid burns from high piping skin temperatures
- Single-point thermal point temperature gun
- Thermal imaging cameras allow for a quick scan of the valves to obtain the temperature profile.

For high-temperature applications, the recycle line may be insulated; therefore, the temperature differential can usually be measured in between the valve flanges. **FIG. 1** shows an example of a thermal image of a recycle valve without a passing condi-

tion. There is a noticeable temperature difference between the pump discharge piping and the recycle line piping. In addition, there is no appreciable temperature differential across the recycle valve. These conditions are clear indications that this recycle valve is not passing.

The main advantage of this technique is the minimal investment cost to perform the surveys and detect passing valve conditions. The main disadvantage of this technique is that it will only identify a passing condition but will not provide the severity of the condition by quantifying the leakage rate.

FIG. 1. Thermal image indicating tight shutoff.

FIG. 2. Ultrasonic flow cell quantifying leakage rate.

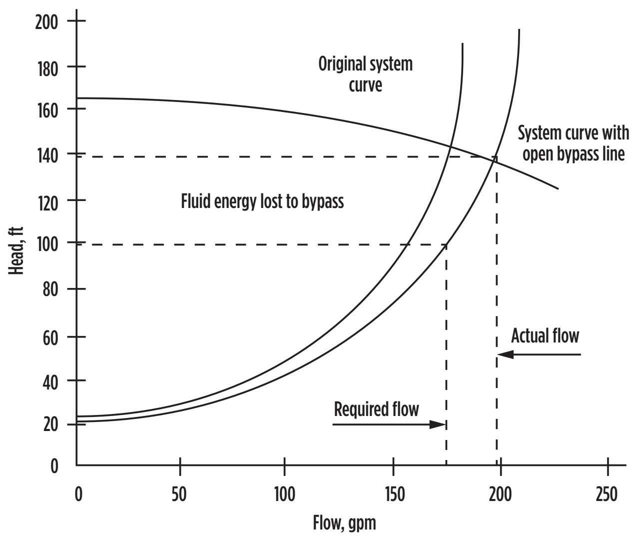

FIG. 3. Fluid energy lost to bypass flow.

AE or ultrasound measurements. These technologies have become more prevalent, and are cost-effective solutions for valve leak detection. The main advantage of these technologies is the ability to detect leakage when differential temperature and other methods are not feasible. The main disadvantages of these methods are the higher initial costs and that they are limited to detecting passing conditions without quantifying the leakage rates. Some technologies claim to provide an estimation of the leakage rate or, at a minimum, a relative assessment of the leakage severity for maintenance planning.

Portable ultrasonic flow measurement. A portable ultrasonic flow device can be utilized to both identify and quantify recycle valve passing conditions. The initial survey using other techniques previously mentioned can be implemented and then followed up with ultrasonic flow measurements to quantify the leakage rate. **FIG. 2** shows a portable ultrasonic flow cell established on a pump recycle line to both detect and quantify the leakage. The main advantages of the portable ultrasonic flow meter are that the leak can be detected and quantified with one measurement. The main disadvantages of this method are the higher initial cost, along with the requirement for training.

Energy savings potential. Regardless of the method used to detect a recycle valve passing condition, it is always advantageous to also quantify the leakage rate to:

- Calculate the potential energy savings and payback analysis for overhauling the passing recycle valve
- Determine the relative severity of the leakage rate for effective maintenance planning efforts—bigger leakers get overhauled first.

There have been many documented cases of recycle valve passing conditions on various high-energy pumps, especially in applications where there is frequent on/off cycling and where there is a high percentage of total suspended solids (TSS). **FIG. 3** shows a graphical representation of the energy lost to an open bypass.

Based on the current cost of power and load factor (operating hr/yr), energy savings are readily calculated. Other benefits and cost savings could also be realized, considering the maintenance costs from the erosion of the valve seats due to prolonged high velocities and the possible cavitation experienced by the valve.

CASE EXAMPLE OF RECYCLE VALVE ENERGY SAVINGS

Seawater shipping pumps. This case study involved a total of 12 seawater shipping pumps that are horizontal, single-stage, radially split between the bearing design, and rated for

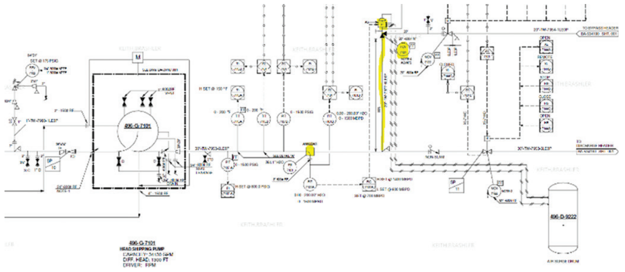

FIG. 4. P&ID of a seawater shipping pump, showing the recycle line takeoff downstream of the flow meter.

34,130 gpm at 1,300 ft total dynamic head (tdh). The pumps are driven by a 15,000-hp electric motor and utilize a 20-in. bypass or recycle line. **FIG. 4** shows the piping and instrumentation diagram (P&ID) of a seawater shipping pump, with the recycle line takeoff downstream of the flow meter.

During the survey of these pumps, it was observed that several of the recycle lines were experiencing significant vibration amplitude, indicating a possible passing condition. The seawater temperature is very close to ambient temperature; therefore, the temperature difference across the recycle valve was not a reliable detection method. Based on the suspected passing condition of several motor-operated valves, a portable ultrasonic flow meter was utilized to both verify and quantify any leakage rates.

Results of the flow measurements validated that several of the valves were passing. The total energy savings from all passing valves exceeded $700,000/yr in electrical horsepower costs alone. The relative severity of all the leakage rates provided a clear maintenance plan for which valves should be overhauled first.

The recycle valves were removed for inspection and overhauled, based on the established priority. **FIG. 5** shows the inspection findings, which revealed significant foreign material (small pea gravel) in the valve, resulting in damage to the valve seat and internals (**FIG. 6**).

Takeaways. There are a few takeaways to highlight, the most important of which was the initial assessment. This is a low-investment activity with a high potential for returns in energy and maintenance cost savings. The preliminary assessment can be performed with minimal hours to achieve a walkdown inspection of each pumping system and to use the differential temperature method or other senses (e.g., look, feel and listen) to identify any potential passing valves.

Other key takeaways and tips include:

- Always try to quantify the leakage rate to optimize the maintenance planning and to calculate energy savings.
- The ultrasonic flow meter is a great option, since it can both detect and quantify leakage with a single measurement.
- Other permanently mounted technologies, such as AE and ultrasound feasibility, can be evaluated after historical data related to recycle valve leakage has been developed.
- Utilize the survey to acquire additional data to perform a complete system analysis during the walkdown inspection. The following are some key variables that can identify additional energy savings opportunities and/or reliability improvements:
  - Energy savings
    - Excessive recycling under normal operating conditions
    - Discharge control output to identify excessive throttling of the process stream
    - Operating point in terms of percentage of best efficiency point flow
    - Identification of situations where more pumps are operated than required to meet system demand
  - Reliability
    - Inspection of mechanical seal support-system integrity
    - Piping integrity related to piping supports, hangers, etc., to identify evidence of external loads on the pump
    - Pump foundation, baseplate and grouting integrity.

In conclusion, the authors would like to challenge plant reliability, maintenance and operations personnel to perform surveys of their critical pumping systems. HP

FIG. 5. An internal inspection revealed significant foreign material (small pea gravel) in the valve.

FIG. 6. The accumulation of small pea gravel in the valve caused significant damage to the valve seat and internals.

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Air-to-air pneumatic booster fail-safe system for valves

In pneumatic valve automation systems, it is common to hear the following terms for valve positions: "fail open (FO)," "fail close (FC)" and "fail last (FL)". These terms refer to the position the valve must take in the event of a failure in the system. In cases where the failure is loss of energy used to move the valve actuator, what do we use to move the valve to the desired failure position? The most common systems are via energy contained in pre-compressed springs. These are known as single-acting actuators. These systems have limitations in the amount of energy they can deliver and the space they occupy.

This article explains how pressurized gas can be stored to be used as a backup system for failure actions and how to do this more efficiently with the use of pneumatic pressure boosters.

Why is it needed to store energy in a valve actuation system? Valves are major elements of piping systems and are often used as safety equipment in the event of system failures. In a pneumatic valve automation system, two main types of failure can occur: loss of signal and loss of energy. When there is a failure in the signal to the controls, which is usually an electrical signal of low voltage (e.g., an electrical signal to the solenoids), this type of failure is known as a loss of signal. When there is a failure in the source of energy used to move the valve actuator (which, in the case of pneumatic systems, is the pressurized gas), this is known as a loss of power or loss of energy.

In normal operation, the system receives a signal to the controls, and a pressurized gas—normally dry, clean air—is sent to the actuator and any pilots present in the system. **FIG. 1** shows a standard schematic of a pneumatic control system for a double-acting actuator with an FC failure action because of a loss of signal.

In the event of a loss of signal, air can be routed to meet an FO or FC requirement, or controls can be selected to trap the compressed gas in the actuator to achieve an FL valve position. In **FIG. 1,** the system routes the air to make an FC in case of a loss of signal.

What happens in cases where the failure is the result of a loss of power? If the energy used to move the actuator is lost, then an FL position can be achieved; however, if opening or closing is needed after this failure action, there is no energy to move the actuator and, therefore, the valve. In these cases, an external source of energy is needed. The most common stored energy systems in valve automation are pre-compressed springs, also called single-acting actuators. When using these actuators, if a power failure occurs, the spring loses resistance and actuates the valve to an open or closed position, depending on the configuration.

Single-acting actuators (**FIG. 2**) have limitations in terms of the amount of energy they can store, which is proportional to the spring elasticity constant and the pre-compression. Therefore, for systems where a high amount of energy is needed (e.g., high-thrust or torque valves), springs are no longer a practical option. In such cases (e.g., for pneumatic systems), stored pressurized fluids are used. The idea behind these systems is to route pressurized gas to move the actuator to an open or closed position in the event of a loss of power or plant air supply pressure loss.

This pressurized air is stored in tanks or vessels. The size of these tanks is determined by the amount of air that is needed to be stored, which depends on the volume of air displaced by the actuator, the maximum air supply pressure and the minimum pressure required to operate the actuator. In systems where large volumes of air need to be stored, the tanks to store this air would also need to be large. To solve this problem, pneumatic pressure boosters can be used.

Pneumatic pressure boosters. Pneumatic pressure boosters are 100% mechanical and are used to boost pneumatic pressure. When air at *X* pressure is introduced to the booster, the pressure activates the mechanical components of the booster. Employing an internal piston, the booster is sectioned into two volumes (i.e., thrust and compression). The thrust volume is the section that generates the

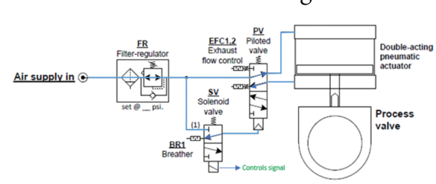

FIG. 1. Pneumatic control system: Double-acting, on-off, fail in last (FL) position.

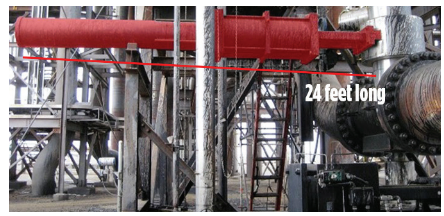

FIG. 2. Single-acting actuator 14-in. tandem mounted on a knife gate valve.

thrust necessary to move the internal piston and compress the air in the compression volume. The compression volume is calculated depending on the ratio at which the pressure is to be amplified. For example, a 2:1 amplifier that will duplicate the inlet pressure will have a larger area than one with a 3:1 or 4:1 ratio. Once the piston reaches the end of the stroke, the movement starts in the other direction. The booster will continue this cyclic motion until the pressure given by the ratio—either 2:1, 3:1 or 4:1—is reached.

FIG. 3. Air tank size reduction comparison.

How do boosters work when used as part of valve automation failure systems? The inlet of the booster is connected to the main air line and the outlet to a storage tank. When pressure enters the booster, the booster increases the pressure according to its design ratio. For example, with a 4:1 booster and an inlet pressure of 60 psig, there will be a 240-psig output to the tank. The tank then stores the air at a pressure of 240 psig.

In normal operation, the regular plant air pressure supply can be used to operate the valve. If there is a failure on this main supply, the pressurized air in the tank is used to operate the valve.

Because the booster enables the air in the tank to be stored at a higher pressure, the size of the tank and the actuator can be significantly reduced.

A practical example. A 20-in. valve, which needs a thrust of 18,000 lb of force to operate, requires a 24-in.-diameter actuator, with an available regular air plant supply of 60 psig. For a failure system with air stored at 60 psig, an 800-gal tank is needed to have enough energy to stroke the valve two times (one full cycle). If a 4:1 pressure booster is added, the pressure is boosted to 240 psig, with a final in-tank pressure after the failure of 100 psig. Therefore, the valve actuator can be sized to 100 psig and not 60 psig. By doing this, the diameter of the actuator can be reduced to 16 in, reducing the volume of air required and resulting in a reduction from an 800-gal tank to a 60-gal tank (**FIG. 3**).

This example illustrates that the use of pneumatic pressure boosters results in more efficient storage of the energy or valve automation systems for failure actions. HP

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Redundant control pilot valve system adds reliability in downstream operation

In downstream processing facilities, such as refineries and chemical plants, downtime is a significant source of lost revenue. At best, this downtime could last a few minutes, due to routine maintenance or a spurious trip of a process valve. At worst, an equipment failure can drag unplanned shutdowns into entire days. Losses of $1 MM/d are not unheard of at this end of the spectrum, and, depending on the issue, the failure can be catastrophic.

Critical process valves, like the emergency shutdown (ESD) valve, must function on demand to keep people and equipment safe. However, the ESD valve does not shut down process flow on its own; it must be activated by a solenoid pilot valve and actuator.

Because of its proximity to the actual process, the ESD valve may get more attention than solenoid pilot valves. However, solenoid valves are just as crucial to the shutdown process, and require monitoring and testing to ensure that they properly operate when needed.

During normal operation, a solenoid valve remains in the open position. It only closes (and activates the ESD valve) if the system detects an issue. While most solenoid valves often remain in the open position for months or even years, this span of inactivity can increase the risk that the valve will not close when needed. If solenoid valves remain inactive for too long, they could experience stiction. If the solenoid valve fails due to stiction, the ESD valve will not be able to stop process flow, leading to the risk of fire or explosion and, ultimately, a plant shutdown.

Refineries and plants can ensure that solenoid valves will operate when needed through diagnostic feedback and preventive maintenance. By monitoring the overall state of these valves in real time and maintaining their condition through automated online testing, refineries and petrochemical plants can get ahead of problems before they result in unplanned downtime or disaster. Redundant architecture is another way users can increase valve reliability and safety. Combining redundant architecture with the continuous monitoring and testing of pilot valves can reduce the risk of downtime, while providing maintenance benefits.

Diagnostic feedback helps avoid shutdowns. When a refinery does not have any kind of feedback from its system, the system will run until there is an issue. Whether an issue is simply inconvenient (e.g., a spurious trip) or potentially catastrophic (e.g., overpressure), facilities must know about it immediately. Therefore, many refineries and petrochemical plants incorporate solutions like pressure sensors, pressure switches and switch boxes that constantly feed data from an entire system loop—including all the equipment that is connected to it—back to their control rooms.

Continuous monitoring of the solenoid pilot valve's position and state can ensure that the valve is functioning properly. Switches can be integrated into solenoid-operated valves (SOVs) to provide position indication (on/off) of the SOVs. The switches then relay this information back to the control room. When users receive the data, they can determine remotely if the valve is in the correct position or not.

Proven in the refining and chemical industries, a proprietary switch[a] provides reliability and durability in mission-critical applications (**FIG. 1**). It detects like a proximity switch and functions like a limit switch, providing higher reliability than conventional switches. In addition, it offers high current ratings, AC/DC and NO/NC wiring flexibility, and non-contact detection of ferrous metal and magnetic targets.

All-in-one diagnostic and preventive maintenance solutions. While the continuous monitoring and feedback that

FIG. 1. Proven in the refining and chemical industries, the proprietary switch[a] shown provides reliability and durability in mission-critical applications.

FIG. 2. The RCS pilot valve system[b] achieves a higher level of process safety and reliability by using redundant, fault-tolerant architectures, high diagnostic coverage and automated testing.

switches provide are essential for detecting issues before it is too late to prevent damage, preventive maintenance is just as important. Solenoid valves require testing—and maintenance, when necessary—to prevent stiction. Reliable all-in-one solutions exist that provide diagnostic feedback and keep systems online, even when solenoid valves are being tested or serviced.

A pilot valve system features redundant architectures that provide extremely reliable diagnostic coverage, a higher level of process safety and online preventive maintenance. With a 2oo2D or 2oo3D architecture, the redundant control system (RCS) combines pressure switches, redundant SOVs and a maintenance bypass in one package (**FIG. 2**). By using a redundant, fault-tolerant architecture, this pilot valve system has no single point of failure that could lead to an unplanned closure of the process valve, which greatly reduces spurious trip rates.

The RCS provides automated online testing with no bypassing required, which allows users to detect potentially dangerous failures prior to shutdown demand. This reduces the Probability of Failure on Demand average (PFDavg) and enables the RCS to be certified as Safety Integrated Level 3 (SIL3) capable. The completely automated, online solenoid valve test features continuous monitoring and diagnostic feedback from pressure switches, and can be set up to run daily, weekly or monthly, reducing maintenance costs and ensuring that functional solenoid valve testing is performed as scheduled. Because testing is performed online with no bypassing required, safety availability is maintained.

Preventive maintenance that eliminates downtime. Preventive maintenance, using diagnostic feedback, helps to increase safety, reliability and operational efficiency by minimizing spurious trips and keeping the process running. However, maintenance of any kind can be its own issue if it takes too long. To avoid extensive periods of downtime, maintenance must be quick and easy.

With three components (two solenoid valves and a maintenance bypass valve), the RCS 2oo2D architecture features a maintenance bypass that allows for online maintenance without process interruption. In this architecture, both solenoid valves are online when the system is functioning normally. If either solenoid valve requires maintenance, users can engage the maintenance bypass mode and quickly fix the issue without interrupting the process. When the solenoid valve is repaired, users can disengage maintenance bypass mode and resume normal operation.

The RCS 2oo3D architecture uses an additional solenoid valve, along with the maintenance bypass valve. Using the same principle as the 2oo2D architecture, if a solenoid valve requires maintenance, users can go into maintenance bypass mode without interrupting the process and quickly fix the issue. Both the 2oo2D and 2oo3D architectures provide high reliability and safety to mitigate spurious or nuisance trips, maintain process uptime and keep workers and equipment safe.

Increased reliability, availability and safety. Diagnostic and preventive maintenance solutions provide users the ability to continually monitor solenoid valve positions from the control room. When users in the control room receive an alert that there is an issue (such as a spurious trip), they can address it and perform maintenance, as needed. The continual feedback that these solutions provide allows facilities to address any minor issues—through preventive maintenance—before they can turn into major issues and potential shutdowns.

While dependable, on-demand shutdown solutions are critical for increasing reliability and allowing easy maintenance, it is also important to partner with a supplier that has a wide range of products to meet unique application needs and that can also provide strong technical support.

Working with a partner that provides complete diagnostic and preventive maintenance solutions—from the device level to the control/DCS level, with analytics and software—can be advantageous at all levels to help refineries and chemical plants improve their operation efficiency and overall performance.

Diagnostic capabilities and preventive maintenance can help refineries and chemical plants increase their safety and reliability, reduce maintenance time and improve their overall operational certainty. Feedback from pressure sensors, pressure switches and switch boxes are crucial, allowing personnel in the control room to monitor equipment and perform preventive maintenance, as needed. All-in-one solutions with redundant, fault-tolerant architectures make it possible to perform online testing and maintenance without interrupting the process.

Integrating dependable, on-demand shutdown solutions backed by a strong partner revolutionizes maintenance, increases reliability, significantly minimizes downtime and ensures that critical valves function when they are needed the most. HP

NOTES

[a] Emerson's TopWorx GO Switch
[b] Emerson's ASCO 2oo2D and 2oo3D RCS pilot valve systems

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Technology and Business Information for the Global Gas Processing Industry

GAS PROCESSING & LNG

GasProcessingNews.com | SEPTEMBER/OCTOBER 2021

A. BLUME,
Editor-in-Chief

The editors of *Hydrocarbon Processing*, sister publication to *Gas Processing & LNG*, will release their "HPI Market Data 2022" annual forecast report in October. This report presents information on global spending and construction projects for the refining, petrochemicals and natural gas sectors, as well as market breakdowns by region and country for each of these industry segments.

In looking at the natural gas/LNG sector, the COVID-19 pandemic has transformed the energy landscape and restructured business priorities. Rather than slowing the energy transition, however, the upheaval caused by the pandemic has fast-forwarded decarbonization efforts by governments and energy supermajors, brought forward the timeline for peak oil demand, fast-tracked the digital transformation in oil and gas, and whetted investor appetites for low-carbon energy technologies.

As the pandemic subsides with greater access to vaccinations, the short-term market volatilities introduced by COVID-19 will give way to more enduring concerns. For fossil fuel producers and processors to survive the business and operational challenges posed by the energy transition—and to take advantage of the opportunities presented by a move toward a greener future—they must apply strategies for emissions reduction, energy efficiency and lower-carbon energy integration. This is particularly true for midstream companies, which deliver the lowest-emissions fossil fuel but find their market shares increasingly challenged by renewable energy.

For in-depth analysis of how these trends will impact global and regional gas/LNG and NGL markets, reserve your copy of the "HPI Market Data 2022" report by visiting store.gulfenergyinfo.com today! **GP**

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Cover Image: Croatia's first LNG terminal is located in Omišalj, on the island of Krk in Croatia. Photo courtesy of LNG Croatia LLC.

Excelerate collaborates with Petrobras on Bahia regas lease

Excelerate Energy LP concluded with Petróleo Brasileiro SA (Petrobras) the negotiation stage of the tender process for the lease of the Bahia regasification terminal. Once the financial and legal qualification and certification stages have been concluded and all regulatory approvals have been obtained, Excelerate will start importing LNG and selling regasified natural gas to its Brazilian customers. Excelerate will deploy one of its existing FSRUs for service at the Bahia regasification terminal.

Excelerate has provided regasification services in Brazil since 2012, with a track record of operational excellence at Petrobras' LNG terminals in Bahia, Guanabara Bay and Pecém. In September 2020, Excelerate's FSRU *Experience* broke an industry record for sendout capacity by reaching 1.06 Bft^3 at the Guanabara Bay LNG regasification terminal. Excelerate operates 13 LNG terminals worldwide.

Petronas delivers its first carbon-neutral LNG cargo

Malaysia's Petronas has completed the delivery of its maiden carbon-neutral LNG cargo to Shikoku Electric. The cargo was delivered from the Petronas LNG Complex in Bintulu to the Sakaide LNG terminal in Shikoku Island, Japan.

The company added that it offset the estimated lifecycle carbon footprint of the LNG cargo through renewables-based carbon credits for the emissions generated from upstream gas exploration and production, transportation, liquefaction and shipping of the cargo.

Additionally, the carbon credits used by Petronas for the delivery were certified through a rigorous verification process under the verified carbon standard program, which is globally recognized and has been adopted by energy players and producers.

In the LNG industry, carbon-neutral LNG is seen as a catalyst to spur greater carbon commitments, with a growing number of LNG consumers seeking ways to reduce their carbon footprint. Petronas is also reducing its carbon footprint throughout its LNG and gas value chain. These carbon-reduction efforts, among others, include powering the PLC with 90 MW of hydroelectricity, conducting flare recovery as well as carbon capture and storage from offshore gas fields.

Australia faces "precarious" gas supply in 2022

Australia's southern states could face a gas shortfall in 2022 unless LNG exporters offer more gas into the domestic market, according to the Australian Competition and Consumer Commission (ACCC).

The report paints a more dire picture than the Australian Energy Market Operator (AEMO) gave in March 2021, when it said plans by billionaire Andrew Forrest to have an LNG import terminal ready by 2022 would stave off any gas shortfall until 2026.

The ACCC said in August that proposed LNG import terminals would not be ready until 2023 at the earliest. "The precarious supply situation for next year highlights the importance of the new Heads of Agreement that the Australian government signed with LNG exporters in January 2021," ACCC Chair Rod Sims said in a statement.

Earlier this year, Australia's three east coast LNG exporters—Australia Pacific LNG, Queensland Curtis LNG and Gladstone LNG—agreed with the federal government to offer uncontracted gas to the local market before it is exported. Gas demand is expected to outstrip supply from production and storage by 6 petajoules in 2022, and the gap could be even larger if demand from gas-fired power plants is higher than forecast, the ACCC said.

The ACCC began its six-month reviews of the gas market in 2017 after gas prices jumped sharply following the startup of LNG exports from the east coast. Gas prices fell last year from around $6 GJ–$11/GJ at the beginning of the year to around $6 GJ–$8/GJ in the second half amid a coronavirus-driven demand slump, but the watchdog said the tightening supply situation could drive prices higher again.

Kinder Morgan closes acquisition of Kinetrex

Kinder Morgan Inc. closed on its previously announced acquisition of Kinetrex Energy in August. The $310-MM acquisition includes two small-scale LNG production and fueling facilities in the U.S., a 50% interest in a landfill-based renewable natural gas (RNG) facility in Indiana, and signed commercial agreements for three additional RNG facilities with construction to begin shortly

Kinetrex is the leading supplier of LNG in the Midwest and a rapidly growing player in producing and supplying RNG under long-term contracts to transportation service providers. The company will continue operations as Kinetrex Energy, a Kinder Morgan company.

India's new LNG plant to boost import capacity by 12%

India will boost LNG imports from 2022 as private firm Swan Energy starts its floating terminal, raising the country's capacity to import LNG by 12% to 47.5 MMtpy.

New demand for LNG by India is expected to support Asian gas prices, which rose to record highs earlier in 2021, partly aided by the transition from coal or oil to gas in developing countries. The 5-MMtpy Swan FSRU, located at Jafrabad in western Gujarat state, will be commissioned in April 2022.

The FSRU was initially expected to be commissioned in 1Q 2021, but the pandemic and two cyclones have delayed the construction of a breakwater needed to make it an all-weather facility. Swan is setting up a jetty and will build more tanks to eventually double the LNG import capacity. Ghana's Tema LNG is now using the FSRU for storing LNG.

India, the world's fourth-largest LNG importer, wants to raise the share of natural gas in its energy mix to 15% by 2030, from the present 6.2%, to cut emissions. State-run gas importers Indian Oil Corp. and Bharat Petroleum Corp., and exploration firm Oil and Natural Gas Corp., have leased 1 MMtpy capacity each at Swan's terminal.

Swan Energy owns 63% of Swan LNG, while two entities of Gujarat state government together have a 26% share. Mitsui holds 11% and is also the technical partner on the project.

Gevo to sell RNG to BP

Gevo's wholly-owned, dairy manure-based renewable natural gas (RNG) project, located in northwest Iowa, has signed definitive agreements with BP Canada Energy Marketing Corp. and BP Products North America Inc. for the sale of Gevo's RNG production.

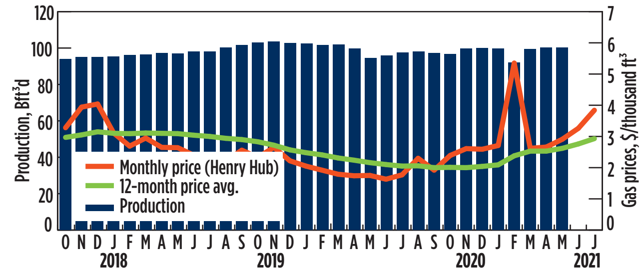
The NW Iowa RNG project is being constructed, and is expected to commence production in early 2022. Upon project completion, NW Iowa RNG is estimated to produce approximately 355,000 MMBtu/yr of RNG. The RNG is expected to be sold into the California market under dispensing agreements BP has in place with Clean Energy Fuels Corp., the largest fueling infrastructure in the U.S. for RNG.

RNG-fueled vehicles are estimated to result in up to 95% lower emissions than those fueled by gasoline or diesel on a lifecycle basis, according to a U.S. Department of Energy study.

It is anticipated that NW Iowa RNG will benefit from environmental product revenues under California's Low Carbon Fuel Standard program and the U.S. Environmental Protection Agency's Renewable Identification Number program.

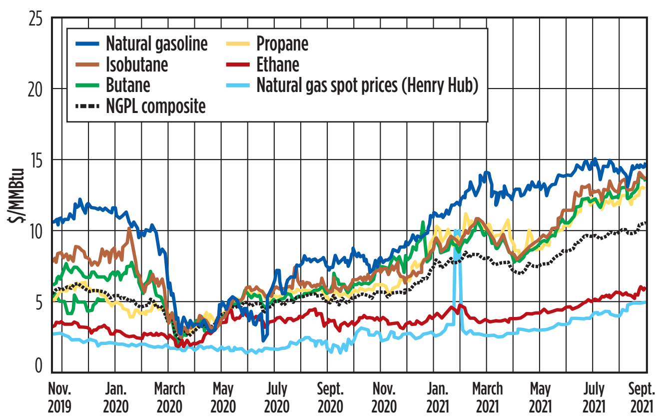
Tightening natural gas market supply/demand fundamentals resulted in a rally in Henry Hub prices from late August into September, with prices up more than 100% on the year. Record hot weather in the Lower 48 states over the summer months sparked high demand for air conditioning, which led to record power burn. Also, supply disruptions following late August's Hurricane Ida continued to affect the supply of natural gas along the U.S. Gulf Coast through September. Extensive damage was recorded to energy production-related infrastructure, including support facilities and natural gas processing plants at Port Fourchon, Louisiana and along the Gulf Coast. **GP**

U.S. gas production (Bft³d) and prices ($/Mcf)

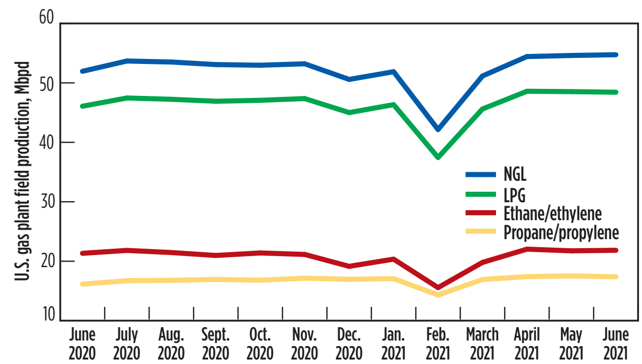


Production equals U.S. marketed production, wet gas. Source: EIA.

U.S. natural gas spot prices at Henry Hub and NGL spot prices at Mont Belvieu, $/MMBtu



U.S. natural gas plant field production of NGL, LPG, ethane and propane, Mbpd



Source: U.S. EIA

Balancing Africa's world-class LNG projects and the environment

S. OIRERE, Contributing Writer, Nairobi, Kenya

The construction of world-scale natural gas processing plants by three of Africa's top natural gas producers has attracted scrutiny, despite efforts to commercialize the continent's hydrocarbon resources and expand energy supply on the continent. This scrutiny has centered on how the project developers intend to achieve the overall goal of monetizing regional gas reserves while ensuring environmental sustainability.

The latest LNG projects in Mozambique, Angola and Nigeria, which are at various phases of implementation, have been forced to address adverse impacts such as liquid effluents, airborne noise, solid wastes, gas emissions, and even encroaching on land already settled or earmarked for settlement or other environmentally safer activities.

Multibillion-dollar gas processing projects include Mozambique LNG, *Coral FLNG* and Rovuma LNG (all in Mozambique), Angola LNG near Soyo in Angola, and Nigeria LNG Ltd.'s Train 7.

Project challenges in Mozambique. Mozambique LNG is operated by Total E&P Mozambique Area 1 Ltd., a wholly owned subsidiary of Total SA, with a 26.5% participating interest. Other partners include ENH Rovuma Area Um S.A. (15%), Mitsui E&P Mozambique Area 1 Ltd. (20%), ONGC Videsh Rovuma Ltd. (10%), Beas Rovuma Energy Mozambique Ltd. (10%), BPRL Ventures Mozambique BV (10%) and PTTEP Mozambique Area 1 Ltd. (8.5%).

Total, which had completed an estimated $16 B in funding for the Mozambique LNG project by July 2020, declared a *force majeure* on the project in April 2021 and withdrew all of its Mozambique LNG project staff from the Afungi site, after the security situation in the Cabo Delgado province deteriorated due to repeated insurgent attacks.

Meanwhile, the *Coral FLNG* project (**FIG. 1**) being developed by Eni and ExxonMobil involves producing and selling gas from the southern part of the Coral field, using a floating plant for liquefying natural gas with a capacity of 3.4 metric MMt, linked to six subsea gas producing wells. The vessel is set to depart the shipyard at the end of 2021, with production startup targeted for 2022.

Elsewhere, the 15.2-metric-MMtpy Rovuma LNG export project is earmarked for development to liquefy and market gas resources from three reservoirs in the Area 4 block of the Rovuma Basin offshore Mozambique. The project is owned by Mozambique Rovuma Venture, a JV of ExxonMobil, Eni and CNPC (70%), Galp (10%), KOGAS (10%) and Empresa Nacional de Hidrocarbonetos (10%).

Developments in Angola, Nigeria. In neighboring Angola, Chevron and Angola's national oil company, Sonangol, are the co-leaders in the 5-MMtpy Angola LNG project west of Soyo. Other partners include Total, Eni and BP.

In West Africa, government-owned Nigerian National Petroleum Corp. (NNPC) has partnered with Eni, Total and Royal Dutch Shell to form the Nigeria LNG Ltd. consortium that is developing Train 7 of the Nigeria LNG terminal. With a capacity of 7.4 metric MMtpy, Train 7 will increase by 30% Nigeria's total LNG output.

For Nigeria, one of the seven countries with the highest gas flaring rates in the world, the Train 7 project would enable utilization of associated gas that is co-produced with oil in the Niger Delta, but is largely flared to the atmosphere. However, according to the Train 7 Project Manager, Tony Attah, the construction of Train 7 will still increase the Nigeria LNG terminal's overall greenhouse emissions.

The Train 7 project is located in Nigeria's Bonny Island, where Attah says that "…climate change is materializing, increasing air emissions [that] threaten the ambient air quality, and [where] noise levels in urban areas approach the limits of acceptability." Attah noted that investments in energy-efficiency improvements, dry-low NO_X technology and noise abatement are foreseen for the Train 7 project.

FIG. 1. Eni and ExxonMobil's 3.4-metric-MMt *Coral South FLNG* vessel is set to commence production in 2022. Photo credit: Eni.

Environmental and social impacts. According to the World Bank, the ideal size for a gas processing plant to support reduction of flared gas is 0.3 $MMsft^3d$–25 $MMsft^3d$. An estimated 400 MMtpy of CO_2-equivalent emissions (CO_2e/yr), including un-combusted methane and black carbon, are flared.

However, the LNG projects underway in Mozambique, Angola and Nigeria are world-scale, as opposed to the small-scale projects that the World Bank recommends for monetization of flared gas. Larger LNG projects, especially those in Mozambique, have been under scrutiny for their potential to adversely alter the sustainability of the environment or ecosystems where they are located, in addition to impoverishing communities around project sites.

For example, ExxonMobil says the Rovuma LNG project—which is expected to emit approximately 2.4 MMt of CO_2e/yr—has been classified as Category A because it has the potential for significant environmental and social impacts on the offshore and nearshore marine environ-

ment and the onshore area surrounding the LNG plant. The offshore environmental impacts of the project would include impacts on the marine environment due to the discharge of drill cuttings, residual muds and hydrotest water; increased marine traffic; and habitat modification.

According to ExxonMobil, key nearshore environmental impacts include dredging, increased noise, introduction of alien invasive species, waste discharges, and loss of estuary and associated mangroves. Furthermore, the company says that setting up a security (exclusion) zone around the LNG facility and associated nearshore infrastructure will impact artisanal fishermen, international maritime traffic, and national and regional marine traffic. Other anticipated impacts include those that trigger air emissions and noise, and those likely to affect visual landscape and impacts to soils, surface water, groundwater, vegetation, reptiles, amphibians, birds and mammals.

In 2014, a joint environmental impact assessment by Anadarko and Eni reported that the Mozambique LNG project would increase Mozambique's greenhouse gas emissions from 0.4%/yr up to 10%/yr. "Given the scale and nature of the project … the overall significance of the impact is not expected to significantly change post-mitigation," the companies wrote in their assessment report.

Meanwhile, a project brief indicates that works at the Angola LNG plant include the widening and deepening of the existing shipping channel at the mouth of the Congo River, the dredging of a turning basin for the LNG facility, and the improvement of the existing Kwanda basin. The dredged material is estimated at 28 MMm^3.

In addition to dredging and land reclamation, the project involved the construction of 1.5 km of shore and slope protection, the installation of 4.5 km of drainage around the fill areas, the installation and monitoring of geo instrumentation, the installation of a concrete oil/water separator and flood valve, and the placing of navigation aids in the channel and basins.

Africa's gas future. For Africa's LNG projects, development of gas processing infrastructure to reduce flaring is a lesser driver compared to the increasing pressure on the continent's gas producers to scale up production and processing to meet international export market demand, especially in Asia and Europe. Natural gas will also continue to be a key ingredient in Africa's energy mix, as natural gas and LNG projects have the potential to generate essential electricity quickly, at reasonable prices.

Whether expanding Africa's liquefaction capacity will support efforts to reduce gas flaring, expand sources of power generation or simply quench the global thirst for more LNG exports, environmental sustainability should remain a long-term concern issue for governments, project developers and consumers. **GP**

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Sensor advances allow pipeline leak detection to take to the skies

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Sustainability and green initiatives have always been laudable objectives, with mission statements around the world confirming commitments to lower emissions and energy consumption, and increase recyclability, to name a few.

However, increasingly over recent years, sustainability has also morphed into a business imperative, as investors, stakeholders and shareholders begin to steer their preferences towards companies that are not just paying lip service to the green agenda but are, instead, actively looking for ways to make their overall carbon footprint and environmental impact as low as possible.

First, the focus was on coal; now, the oil industry thinks it might be next. Indeed, a recent article in *Forbes* magazine stated: "One of the primary reasons that all three big companies (e.g., BT, Chevron, ExxonMobil) are so focused on reducing their emissions of methane and other greenhouse gases is simple: they view it as being in their best economic interest, rather than risk seeing investors flee to other industry segments perceived as being more environmentally friendly."

These big three companies—coupled to numerous other large, medium and small companies—can have a hugely positive impact on the reduction of unwanted methane emissions. This is especially true when you consider that, according to the U.S. Energy Information Administration (EIA), the natural gas pipeline network in the continental U.S. comprises about 3 MM mi of interstate and intrastate pipelines that link natural gas production areas and storage facilities with consumers. In 2019, this natural gas transportation network delivered approximately 28 Tft^3 of natural gas to 77 MM customers.

If investor pressure is not enough, stricter legislation is also forcing companies to appraise the way they install and—arguably, more importantly—maintain their networks. The U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA) published an advisory bulletin in June this year that, in summary, states: "PHMSA is issuing this advisory bulletin to remind each owner and operator of a pipeline facility that the 'Protecting our infrastructure of pipelines and enhancing safety act of 2020' (PIPES Act of 2020) contains a self-executing mandate requiring operators to update their inspection and maintenance plans to address eliminating hazardous leaks and minimizing releases of natural gas (including intentional venting during normal operations) from their pipeline facilities. Operators must also revise their plans to address the replacement or remediation of pipeline facilities that are known to leak based on their material, design, or past operating and maintenance history. The statute requires pipeline operators to complete these updates by December 27, 2021."

Obviously, a potentially significant time gap exists between updating plans and actually executing them, but this gives companies the breathing room to source and integrate technologies and procedures that will provide the best possible means to monitor and maintain their pipeline infrastructures. In fact, the PIPES Act of 2020 directs gas pipeline operators to use advanced leak-detection technologies to conduct leak detection and repair programs that protect the environment and enhance pipeline safety.

Reactive and proactive maintenance are key facets contributing to the efficient operation of any system—big or small, consumer or commercial. In most cases, the expenditure of time and effort is justified in financial terms, but fiscal matters are only part of the full picture. In the case of pipelines, leaks and their resulting environmental impact must now also be factored in and given equal, if not higher, billing.

The primary driver and antagonist in all of this is methane, the main component of natural gas. Methane emissions have increased by 9% globally in the last decade. Although naturally occurring, huge amounts of methane are emitted from man-made sources, such as coal mining, landfill, wastewater treatment and, of course, oil and natural gas production and transportation.

The U.S. Environmental Protection Agency (EPA) explains why: "Methane is the second most abundant anthropogenic (human-caused) greenhouse gas after carbon dioxide (CO_2), accounting for about 20% of global emissions. It is more than 25 times as potent as CO_2 at trapping heat (over 100 yr) in the atmosphere and over the last two centuries, methane concentrations in the atmosphere have more than doubled, largely due to human-related activities. Because methane is both a powerful greenhouse gas and short-lived compared to CO_2, achieving significant reductions would have a rapid and significant effect on atmospheric warming potential."

Looking at it positively, the UN Framework Convention on Climate Change elaborates: "A Global Methane Assessment released in May by the Climate and Clean Air Coalition (CCAC) and the United Nations Environment Programme (UNEP), shows that human-caused methane emissions can be reduced by up to 45% this decade. Such reductions would avoid nearly 0.3°C of global warming by 2045 and would be consistent with keeping the goal of the Paris Agreement to limit global temperature rise to 1.5°C (2.7°F) within reach."

The International Energy Agency's (IEA's) Sustainable Development Scenario (SDS) says that emissions from the pipeline sector will need to fall to around 20 metric tpy by 2030—a drop of more than 70% from levels in 2020.

Finally, and somewhat under the radar,

U.S. President Biden also issued an executive order in May 2021 directing federal agencies to incorporate the economic risks from climate change into decision-making. Although this does not specifically address fossil fuel investments, the concern among energy producers is that financial regulators will ultimately use their power to steer banks and investors away from the industry.

This raft of national and international legislation is setting a very high bar for the natural gas industry, not just in the U.S., but around the world. The problem is that the scale of operations that must be addressed is immense. The 3 MM mi of pipelines in the U.S. alone—some of it in incredibly remote areas—present a massive undertaking for reactive maintenance, let alone proactive.

Mobile gas leak detection technologies—both portable and vehicle-mounted—do exist, and are ideal for easier-to-access locations. However, when the hostile and sometimes near impenetrable or inaccessible nature of some locations is considered, even the most rugged 4×4 vehicle will have issues.

Aware of this impending legislation and the ethical, financial, societal and political turmoil behind it, development work has been put in motion to enhance sensor technology and, more importantly, make it far more portable.

Drone technology is the answer. Thanks to significant advances in sensor technology, especially those relating to cavity enhanced laser absorption spectroscopy techniques, methane can now be detected with a sensitivity more than 1,000 times higher and over 10 times faster than conventional leak-detection tools. More importantly, this technology is not only sensitive and fast, but also small enough to be mounted on commercial drones.

The author's company has released a new technology[a] that can be mounted on low-cost commercial UAVs capable of carrying 3 kg (6.6 lb) payloads (**FIG. 1**). Flying at altitudes of 40 m (130 ft), or higher, and at speeds up to 88 km/hr (55 mph), the drone-mounted solution[a] can detect, quantify and map leaks up to 100 m (328 ft) from natural gas distribution and transmission pipelines, gathering lines, storage facilities and other potential methane emissions sources.

Previous leak-detection efforts relied on slow, qualitative, analog sensors or expensive delicate cameras to find leaks, but the extremely fast response and high precision of the new analyzer technology (**FIG. 2**) allows scientists and researchers to reliably quantify greenhouse gas fluxes, which provides important information when studying the complex environmental processes affecting climate and pollution.

This new drone-based system[a] has become available at the ideal time for pipeline operators. Based on the stipulations in the PIPES Act of 2020, operators can now update maintenance plans with the knowledge that the technology is available to make remote leak detection a far simpler and cost-effective proposition. These advances in sensor technology are not restricted to drones—they can also be easily deployed in vehicles and handheld monitoring systems, providing a defense-in-depth approach to detect, map and quantify large, small and even hidden leaks with unprecedented speed, reliability and accuracy throughout the entire natural gas infrastructure, including upstream, midstream, downstream and gas utilities. **GP**

FIG. 1. The drone-mounted solution[a] can detect, quantify and map leaks up to 100 m (328 ft) from natural gas distribution and transmission pipelines, gathering lines, storage facilities and other potential methane emissions sources.

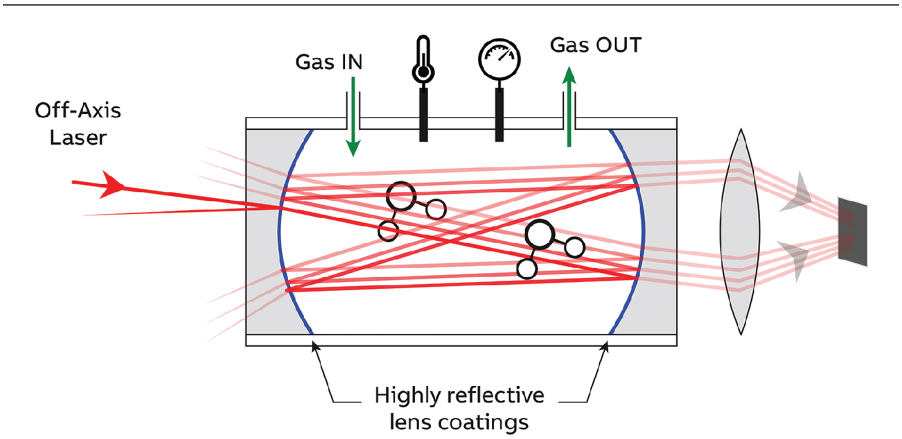

FIG. 2. The gas leak detector[a] enables scientists and researchers to reliably quantify greenhouse gas fluxes, providing important information when studying the complex environmental processes affecting climate and pollution.

NOTES

[a] ABB's HoverGuard

DOUG BAER is the Global Product Line Manager for laser analyzers within the ABB Measurement and Analytics Division, where he invents, develops, manufactures and sells laser-based instrumentation for ultra-sensitive and accurate measurements of gases, liquids and isotope ratios for atmospheric and environmental monitoring, industrial process control and homeland security. Dr. Baer is an inventor of ABB's patented laser-based technology and the industry-leading natural gas leak detection platform. Before joining ABB, he served as the President of Los Gatos Research. Dr. Baer earned a BS degree in engineering physics from the University of California, Berkeley, and an MS degree and PhD in mechanical engineering from Stanford University.

Prevent unplanned shutdowns for LNG liquefaction facilities

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Although an unplanned shutdown is an integrated part of the operational and safety management system of an operating plant, unplanned shutdowns for a modern LNG liquefaction operating facility often become some of the costliest events for the facility owner. Each of these events negatively affects the owner's business due to loss of production and reputation. With today's world transitioning to green energy, the benefits to LNG owners by adopting an advanced prevention and maintenance program to prevent unplanned shutdowns are obvious and financially prudent.

Challenges in preventing unplanned shutdowns. An unplanned or emergency shutdown of an operating facility due to safety, asset and environmental risks is a necessary step for owners to take the process and equipment in emergency to a safe state. Unfortunately, unplanned shutdowns for a modern LNG liquefaction facility often become frustrating events for the owners due to loss of production, which can equate to millions of dollars daily.

Preventing unplanned shutdowns and finding effective solutions are challenges facing LNG facility owners in the following areas:

- Due to the complexity and scale of a modern LNG facility, the potential failures of all components cannot be fixed at once during a scheduled turnaround due to variations of the component failure rate. Between scheduled shutdowns, a failure will always occur at a seemingly unexpected time due to randomness or unpredictability.
- Tens of thousands of active components in an LNG facility must be maintained simultaneously and properly to sustain stable operation. The task of a facility's maintenance team is enormous, especially when a preventive maintenance approach is used.
- Identifying the potential risk of all component failures is not an easy task during the engineering design phase. A limited number of unplanned shutdowns are initiated automatically as designed (e.g., through shutdown interlocks). The majority are initiated manually by the operator depending on situations onsite, which puts a tremendous amount of pressure on the facility's operations and maintenance teams.
- The traditional reactive maintenance approach is less useful in preventing unplanned shutdowns because the failure and shutdown have already occurred.
- The availability of accurate equipment reliability and failure rate data is key to the success of a preventive maintenance program. Sometimes, equipment breaks down earlier than what the vendors recommended or predicted from historical data, which adds more challenges to rectifying the true turnaround intervals of the equipment in utilizing a preventive maintenance approach.
- Root causes to failures leading to unplanned shutdowns vary.
- Many unplanned shutdowns were due to design deficiency and human error, which are often nightmares to owners as they are less related to equipment aging or wear and tear. It is difficult for a plant maintenance team to tackle such failures by conventional plant maintenance approaches.

Strategies to prevent unplanned shutdowns. The prevention of unplanned shutdowns for large-scale and complex LNG facilities is more than just reducing or minimizing failures. Owners that adopt advanced prevention and maintenance programs will be the ultimate winners. While all prevention and maintenance programs share a common goal to prevent failures of equipment and reduce downtime, for an LNG facility, an advanced prevention and maintenance program should be characterized by:

1. Covering the entire lifecycle of the facility—i.e., from engineering design through plant operations
2. Adopting preventive and predictive approaches
3. Utilizing advanced technologies in monitoring, data acquisition and data analysis and management, such as a computerized maintenance management system.

Implementing such a program requires the owner's systematic deliberation in the choice of engineering management, asset management, and operational and safety management, including a risk management program, an engineer program or project management consulting (PMC) program, etc.

Prevent unplanned shutdowns for LNG facilities. The history of the LNG industry has shown that many costly unplanned shutdowns were rooted to hazards or faults laid in the various engineering phases—conceptual design, pre-FEED feasibility studies, FEED and EPC. Likewise, efforts made to ease maintenance and operability during the engineering phase have been found to significantly reduce a plant's unplanned shutdowns. The prevention of unplanned shutdowns can be achieved by good engineering practices and sound equipment design—selection, specification and cold-eye review in compliance with codes, standards and regulations. Some good examples of inher-

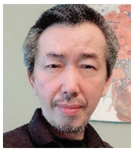
ently safer design include utilizing advanced technologies, proper equipment design margins, equipment spare/redundancy, multiple trains, enforcement in equipment support structures and associated piping, upgraded materials of construction, etc.

The success also depends on the planning and scheduling of all related engineering activities focusing on the prevention of unplanned shutdowns, including value engineering, alarm/trip setpoints rationalization, functional safety, risk analysis of equipment failure mode, etc. For the development of a new LNG facility, it is always a good practice to start the program early, such as in the engineering design phase. It will be beneficial to make the owner's maintenance strategy known to all parties involved (engineering contractors, licensors, equipment manufacturers, etc.) to help prevent unplanned shutdowns, and to put relevant design requirements in the basis of design. The owner's engineers typically play an important role in ensuring that all of these procedures align with the owner's maintenance philosophy.

During plant operation, proper maintenance of all major equipment systems is of paramount importance to minimize the potential of unplanned shutdowns due to component wear or equipment failure. While details and techniques for implementing an advanced maintenance program may depend on the specific maintenance method chosen, in general, several steps may follow:

1. Identify target equipment or systems, including those that have emergency shutdown interlocks in design, based on potential risk level of failure.
2. Evaluate the current conditions of target equipment or systems based on plant monitoring data and inspection in reference to historical reliability data.
3. Set maintenance priorities accordingly. If a shutdown for maintenance and inspection is unavoidable, then the scheduled shutdown interval may be re-evaluated based on the potential risk level of major asset equipment to minimize the potential risk of failure, maintenance/repair cost, and cost due to loss of production.

Sometimes, unplanned shutdowns can occur due to human error. While numerous factors can contribute to human error, the utilization of respective corrective actions and best practices can significantly reduce the failures due to human error that lead to unplanned shutdowns. For example, comprehensive training of maintenance personnel and field operators can minimize unanticipated events during plant operation involving human error, as will more in-depth familiarization in the operation and maintenance of different equipment at various working environments. **GP**



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Turbomachinery configuration for LNG project concept selection

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Refrigerant compressors are the pumping heart of every LNG plant. Today, these compressors are usually centrifugal, and they vary in size and configuration according to the context of the project. Steam turbines, gas turbines (heavy-duty or aeroderivative) and electric motors—or a combination of these three—are all possible options to drive the refrigerant compressors. It has been demonstrated that a single shaft can drive one, two or three compressor casings depending on the plant capacity, the liquefaction process technology used and the balancing needs of power. This is particularly interesting, as drivers with larger output power and efficiency can be considered.

This article[a] elaborates on the selection of an optimum turbomachinery configuration from a technical perspective, building on technical experience attained through working on multiple concept and early front-end engineering design (FEED) studies for turbomachinery selection in LNG projects, some of which have been executed.

Introduction to compressors. Steam turbines were used as mechanical drivers for main refrigerant compressors in LNG plants until the 1980s, after which time gas turbines started to replace them. Electric motors have been used only occasionally in large-scale plants, but they have become popular at small- and mid-scale facilities.

Steam turbines can be custom-made to deliver any power level likely to be required by an LNG refrigerant compressor; however, the largest referenced electric motors are capped at around 75 MW. The largest gas turbine used to date is the heavy-duty Baker Hughes Frame-9, used across the LNG mega-trains at Qatargas' Ras Laffan terminal. These turbines deliver 132 MW at International Organization for Standardization (ISO) conditions. They are catalogue machines available in discrete sizes, which makes the selection of an optimum gas turbine and shaftline configuration more challenging.

Compressor selection process. The production capacity of an LNG plant is directly linked to the power available from the refrigeration machinery. Consequently, the selection of the driver and the arrangement of the compressors is performed very early in a project, no later than at the early FEED phase. The final selection is made by the owner-operator based on engineering studies performed with the assistance of a specialized consultant (backed by a team of process and rotating equipment engineers) and in collaboration with the liquefaction process licensor. The overall selection study, all the way up to the recommendation to the owner, is supervised and led by the project management team.

At the beginning of a project, awareness on the general guidelines, characteristics and key criteria for the selection process should be determined with the owner. For example, the standardization of the gas turbine fleet could be an advantage where spare parts interchangeability and familiarity of operators and maintenance personnel with a specific gas turbine model are beneficial to operations.

Commercial relations should also be considered—for example, in a case where the owner favors one supplier with existing services agreement or, on the contrary, where the owner prefers to avoid a gas turbine supplier with limited service facilities in the country where the gas turbines will be installed.

Finally, some owners do not accept non-proven gas turbines that require qualification before the FEED or engineering, procurement and construction (EPC) phases; whereas other owners are willing to undertake a qualification process, including rigorous verification and extensive testing.

In these times of enhanced sensitivity to the carbon footprint of liquefaction facilities, electric motors as prime movers for the main refrigerant compressors are increasingly being taken into consideration. This is a departure from the situation to date, where electric motors have been the exception. For example, the promise of availability of a nearby source of power from the electric grid at a competitive price led the Snøhvit LNG plant in Norway to select a 65-MW electric motor for each compressor shaftline using the Linde Mixed Fluid Cascade (MFC) process. Also, because local regulations forbid fired equipment in an environmentally sensitive location, Freeport LNG on Quintana Island, Texas applied 75-MW variable-speed electric motors on each shaftline using the Air Products Propane Mixed Refrigerant (AP-C3MR) process.

In the coming years, it is anticipated that electric motor drives may become an attractive option due to the opportunity to reduce CO_2 emissions by mixing in low-carbon sources of electricity.

Technical assessment. The first step in the technical assessment is to determine the required prime mover power for each shaftline depending on the LNG plant design and compressor configuration (see FIG. 1). This will depend on the targeted range of LNG plant production capacity in MMtpy, how many liquefaction trains are envisaged, which refrigeration process will be used and how many refrigeration cycles, and finally how many refrigeration compressor strings per train.

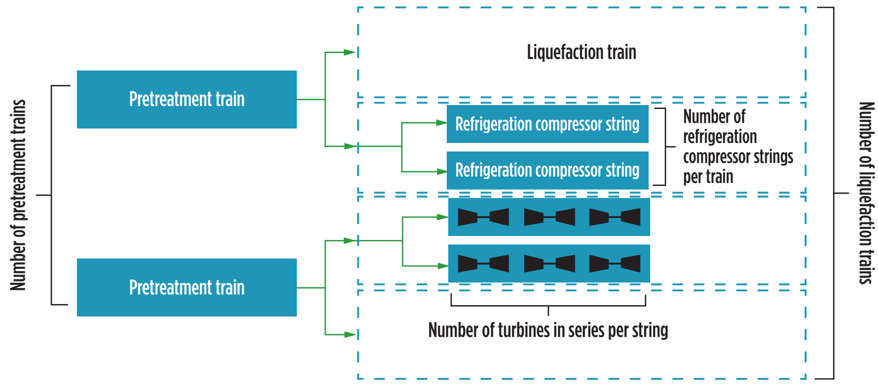

FIG. 1. LNG plant screening of architecture.

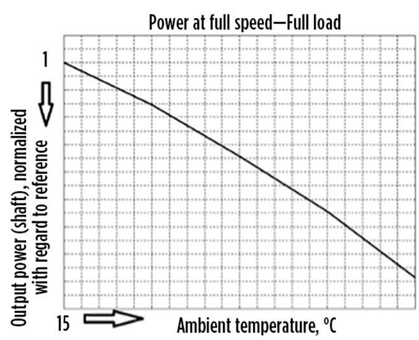

FIG. 2. Gas turbine typical de-rating curve—power vs. ambient temperature.[b]

Several types of drivers can be considered to drive LNG compressors (gas turbines, steam turbines, motors), but once the choice is made it will usually apply to all the main refrigerant compressors for reasons of interchangeability, flexibility and maintainability. The selection should be reached in parallel to defining the compressor machinery arrangement to obtain the required balance of power and to select the standardized driver model for all shaftlines. Steam turbines and electric motors could be custom made to the required shaftline power; however, gas turbines come in discrete sizes and, therefore, the selection of optimum gas turbine depends on matching the available gas turbine models and versions.

At the early stages of concept definition, as many as 15 architectures or more can be screened and quantitatively ranked to support the owner's selection when including the liquefaction process, machinery arrangement and other key selections. The criteria defined with the owner for the ranking and the selection are, at this stage, crucial to best match the owner's objective and to ensure the success of the project.

Gas turbine as a prime mover. Both heavy-duty gas turbines and aeroderivative gas turbines have been applied in LNG plants to drive main refrigerant compressors. The heavy-duty gas turbines have been adapted to mechanical drive from the versions built especially for the power generation industry and proven through decades of use. The power generation industry requires large power at a fixed speed, typically 3,000 rpm for a 50-Hz electric grid network and 3,600 rpm for a 60-Hz network. As a result of these constraints, large, heavy-duty, gas turbines have evolved (more than 500 MW in the largest sizes) with a single drive shaft. Startup torque for an offline generator is very low; however, the adaptation to mechanical drive in LNG plants implies the addition of large starter motors to overcome the compressor start from standstill torque.

Aeroderivative gas turbines were initially developed for aircraft engines, but in most cases have been first used in the power generation industry before being adopted for mechanical drive. Adaptation includes the addition of a free power turbine and the optimization of inspection and maintenance cycles that are obviously much longer for LNG trains than for commercial aircraft. The LM9000, which is now in the manufacturing stage for Novatek's Arctic 2 project, is an aeroderivative gas turbine derived from the world's most powerful civil aircraft engine and specifically developed for mechanical drive service in LNG.

Irrespective of the model, a referenced gas turbine must have field-proven design, meaning that it must have a proven and successful track record of performance in equivalent service, operating and process conditions. The gas turbine must have completed 25,000 hr for aeroderivative gas turbines/32,000 hr for heavy-duty gas turbines of continuous satisfactory operation in a continuous process plant without major problems or modifications.

Gas turbines with references coming only from the power generation industry cannot be considered as suitably referenced for mechanical drive application, as described. To qualify as a mechanical driver, they must be verified for the following:

- The rotor dynamics of the shaftline in the mechanical drive application must account for the gas density change that will occur during the operation of the coupled compressor, impacting the axial stability of the shaftline.
- The much higher startup torque for the mechanical drive should, if possible, allow startup from settle-out pressure to avoid flaring.
- In high-power gas turbines, the coupling and/or gearbox might not be referenced considering that the service factor will be higher in the mechanical drive than in power generation applications.

Once the required gas turbine site output power is estimated, then the ISO power can be determined by considering the gas turbine de-rating at the most demanding site condition and the worst operating condition. Gas turbine de-rating means that the gas turbine will deliver to the site less power out than the ISO power that is declared on the nameplate.

Several factors adversely affect the output power of gas turbines, including ambient temperature, pressure drop at the inlet and outlet, and factors relevant to fouling and aging. Roughly speaking, with an increase of 1°C in ambient temperature, the output power decreases by 0.7%–0.8%. Aeroderivative gas turbines are more sensitive to variations in ambient conditions compared to heavy-duty gas turbines.

On the other hand, fouling is a condition caused by the ingress of contaminants from the ambient air sticking on the axial air compressor blades and reducing their aerodynamic performance. Aging is related to the deterioration of gas turbine components due to extended operation, especially for the hot section.

De-rating extents are unique to each gas turbine model and version, and the

gas turbine supplier provides the de-rating curves for each gas turbine model and version accordingly. A typical de-rating curve is shown in FIG. 2 revealing how power output decreases with the increase in ambient temperature. Similarly, de-rating curves for other factors, such as the inlet and exhaust pressure drops, are used to estimate the actual power output of a specific gas turbine.

Compressor arrangement. Until recently, LNG plants had a maximum of two main refrigerant compressor casings installed on the same shaftline, with a variable-speed starter motor usually added to single-shaft gas turbines. A longer and more complex shaftline will increase the complexity of the torsional analysis study, further to the inter-harmonic excitations from the variable speed helper motor, when they exist.

A successful step-out was applied in the Yamal LNG project (FIG. 3), where three compressor casings plus a variable-speed start/helper motor were installed on the same shaftline, which extended in length to 50 m (FIG. 4).

The use of a gearbox will also lead to power losses that must be taken into account. Almost 2% of transmitted power could be lost due to the gearbox; however, it must be noted that technical improvements are ongoing to reduce such losses. The addition of a gearbox to the shaftline will also impact the CAPEX of the project, noise emissions and the maintenance of the compressor shaftline, especially if a gearbox noise hood is added to meet noise specifications.

Depending on the size of the driver, one or several compressor casings can be installed on the same shaftline, and the temptation can be great to limit the number of shaftlines for CAPEX purposes. Selecting a bigger driver with several compressor casings, instead of selecting several smaller ones to drive one compressor casing, might seem to be less expensive from a machine perspective. However, the CAPEX savings of this selection is less obvious if the complete installation of the train is considered.

Applying large gas turbines would lead to a horizontally-split design for the middle casing to enable maintenance of the compressor rotor. This casing will have a bottom/bottom nozzles configu-

FIG. 3. Novatek's Yamal LNG project in Russia.

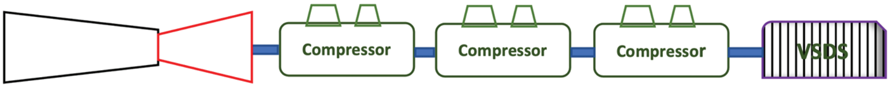

FIG. 4. Three compressor casings on a common shaftline with a variable-speed helper motor.

Refrigerant compressors are the pumping heart of every LNG plant. Steam turbines, gas turbines (heavy-duty or aeroderivative) and electric motors—or a combination of these three—are all possible options to drive the refrigerant compressors.

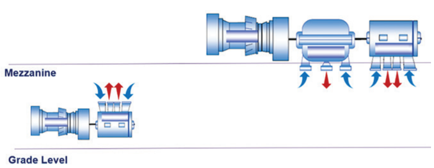

FIG. 5. Grade-level vs. mezzanine-level installation of the shaftline.

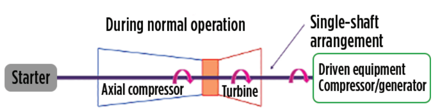

FIG. 6. Single-shaft arrangement in gas turbines.

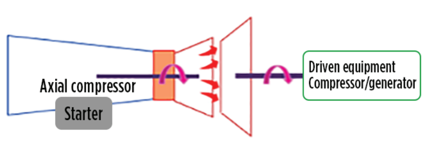

FIG. 7. Dual-shaft arrangement in gas turbines.

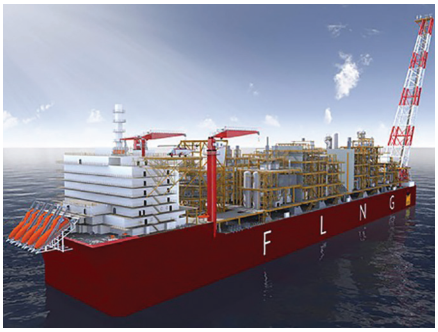

FIG. 8. The *Coral FLNG* project.

ration so that the upper half of the casing can be opened to extract the rotor. This will require mounting the entire shaftline on an elevated table, as shown in **FIG. 5**. For modular applications, it will lead to an increase in the size of the module, and when installed in a closed building it will lead to higher building elevation and increased heating, ventilation and air conditioning (HVAC) load. All of these factors might eventually make the larger gas turbine more expensive than several equivalent smaller ones.

Gas turbine technologies. Historically, heavy-duty gas turbine drivers have been selected to drive LNG compressors considering their robustness, and consequently their high availability levels; accordingly, a 1 × 100% shaftline arrangement was considered (for example, in the Yemen LNG project). However, with an aeroderivative (or dual-shaft heavy-duty) gas turbine, parallel operation (i.e., 2 × 50% shaftlines) was introduced to overcome the smaller sizes available in terms of power output and to limit the impact on production due to lower availability. In addition, the 2 × 50% (or 3 × 33%) shaftline arrangement can improve the turndown efficiency of the liquefaction unit.

Turndown capacity of a compressor, before the start of recycle, is generally considered at 30% of the rated flow, which is sometimes insufficient for process purposes if only one compressor is used.

Efficiency. One of the main advantages of aeroderivative gas turbines is the much higher operating efficiency compared to heavy-duty gas turbines. This efficiency is the result of the higher pressure ratio developed by the axial air compressor and, consequently, the greater gas expansion in the power turbine. In the specific case of the triple-shaft LMS-100 from Baker Hughes/General Electric, intermediate air cooling allows exceptional axial air compression ratios and an efficiency reaching 44%.

However, the selection of the gas turbine will directly impact the design of the fuel gas system of the plant and particularly the size of the boiloff gas compressor, as the fuel gas pressure requirement will be higher for an aeroderivative gas turbine compared to a heavy-duty gas turbine, which depends on the selected gas turbine model and ambient conditions. Roughly speaking, heavy-duty gas turbines require fuel gas pressure around or below 30 barg compared to aeroderivative gas turbines, where the fuel gas pressure can range from 42 barg–60 barg, such as for the SGT-A65 (Trent 60) from Siemens, which is no longer in production.

Shaft arrangement/speed variation. Most heavy-duty gas turbines come in a single-shaft arrangement (**FIG. 6**), although some exceptions exist, such as the Frame-5 from Baker Hughes/General Electric and the H-100 from Mitsubishi Hitachi Power Systems. However, aeroderivative gas turbines come in a multi-shaft (dual- or triple-shaft) arrangement (**FIG. 7**).

Accordingly, aeroderivative gas turbines operate at a wider speed range of 80%–105% of the rated speed and do not require a large starter motor, while speed variations in heavy-duty gas turbines are limited to 2%–3% of the rated speed and require a large starter motor to spin the heavy shaftline from standstill to firing speed.

CAPEX. Aeroderivative gas turbines are naturally more expensive than heavy-duty gas turbines due to the additional axial compressor stages and higher compression ratio (and compressed air temperature) that require the use of exotic material, such as titanium alloy, whereas stainless-steel alloys are sufficient in heavy-duty gas turbines.

A second consequence is that there are roughly 30% more internal components for an aeroderivative gas turbine compared to heavy-duty gas turbines of the same power class.

Varied onshore/offshore applications. Aeroderivative gas turbines are much lighter and more compact compared to heavy-duty gas turbines, which is why aeroderivative gas turbines are the preferred choice for offshore applications. They have consequently been selected for all FLNG vessels. The PGT25+G4 aeroderivative turbine is less than one-third the weight of its equivalent heavy-duty gas turbine, the Frame-5D.

Onshore LNG plants applied heavy-duty gas turbines until the LM2500, an aeroderivative gas turbine that was used at the Darwin LNG project to improve efficiency. Many other projects have followed,

including Curtis Island LNG, Papua New Guinea LNG, Wheatstone LNG (with an LM6000PF turbine) and, recently, the Arctic LNG 2 project, which is still under construction, with an LM9000 turbine.

For offshore applications, the PGT25+G4 gas turbine from Baker Hughes/General Electric's LM2500 family has been applied at the *Coral South FLNG* (**FIG. 8**), which operates on a dual mixed-refrigerant process. The PGT25+G4 has been also applied at Petronas' *PFLNG Satu,* which operates on an AP-N process, as well as several other FLNG facilities, such as Golar FLNG vessels and the *Gorskaya FLNG.* An LM6000PF, another aeroderivative gas turbine, has been applied at Petronas' *Rotan FLNG* to deliver roughly 30% more output power compared to a PGT25+G4 gas turbine.

Shaftline power enhancement. Aeroderivative gas turbines are more sensitive to daily and/or seasonal fluctuations in air temperature than heavy-duty gas turbines. To compensate for periods of high ambient temperature, inlet air chilling can be used to mitigate the slight adverse impact on output power. When the power shortage is high at hot ambient, a helper motor is applied to supplement the power shortage from a heavy-duty gas turbine.

Waste heat recovery unit. A waste heat recovery unit (WHRU) can be fitted at the exhaust stack of the gas turbines for the main refrigerant compressors when the power margin between gas turbine output power vs. driven compressors absorbed power allows. Roughly speaking, adding a WHRU could lead to an approximate 0.4% drop in output power of the gas turbine, depending on the operating conditions and the design of the WHRU.

Maintenance considerations. Maintenance intervention is more frequent but less time-intensive for aeroderivative gas turbines compared to that required for heavy-duty gas turbines. Dual-shaft gas turbines, in general, are much easier to maintain. General Electric's Frame-5 is an example of a heavy-duty gas turbine with a dual-shaft arrangement.

A new generation of large, dual-shaft, heavy-duty gas turbines has been initiated with the introduction of the MHPS H-100 for use in LNG plants. This turbine offers shorter shutdowns for maintenance. In addition, the dual-shaft design eliminates the need for a large starter motor.

Novelty management. The adoption of new, unproven technologies should be avoided wherever possible. However, the increase in LNG train size and the interest in scale as a way of reducing CAPEX sometimes leads to gas turbines being selected while still in the development phase, and with risks that are still under assessment by the gas turbine manufacturer.

An example of a new development is Baker Hughes/General Electric's LM9000 aeroderivative gas turbine, which is based on the GE-90 aircraft engine. As a two-shaft machine with ISO shaft power reaching approximately 70 MW, it is capable of revolutionizing upcoming LNG plant designs. The adoption of the LM9000 on the Arctic LNG 2 project implied a qualification program and additional studies, simulations and tests during the engineering phase of the project.

A "technology qualification" process consists of an in-depth analysis of the design, development and integration of new or borrowed technologies to identify risks and implement mitigations. The process follows a structured procedure to identify and screen novelty designs within a new product and assess the readiness level of each novelty. This qualification program is normally led by the owner-operator and is based on the owner's internal processes and field experience.

A first step in such a qualification process is the identification, component by component, of all novelties within the gas turbine design. Examples include a new material or coating, a new production process, new operating conditions or a combination of these items. Once identified, and after technical validation is performed, a risk mitigation plan must be established. This will often result in demanding tests such as a full-speed, full-load string test or an endurance test, which must be taken into account in the overall schedule of the project.

Takeaway. Turbomachinery selection for LNG plants encompasses several steps of screening to reach the optimum driver and compressor configuration choice. This broad choice is impacted by the unique aspects for each LNG plant, including the production capacity, train size, CO_2 emissions and other environmental targets, site location (particularly when not onshore), site ambient conditions and variations, demand for utilities, availability of electrical power from the grid and the need for waste heat recovery.

A successful selection process is a joint effort between the owner and a specialized LNG engineering contractor. The optimum selection of driver and compressor configuration is achieved through a comprehensive assessment by an interdisciplinary team of engineers and estimators. **GP**

ACKNOWLEDGMENT

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NOTES

[a] This article was originally presented at GPA Europe's Annual Meeting and Technical Meeting in 2020.

[b] X-axis and y-axis values are not shown due to copyright reasons.

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Optimize the design and configuration of ambient air heaters for LNG regasification

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An LNG regasification terminal converts LNG from a temperature of nearly −160°C back into natural gas at atmospheric temperature for distribution across a consumer network. The regasification of LNG is generally conducted using one of the following types of vaporizers: an open-rack vaporizer, a submerged combustion vaporizer, an ambient air vaporizer or an intermediate fluid vaporizer.

The selection of vaporization technologies for a regasification terminal is determined by CAPEX, OPEX and associated environmental issues at the site. Looking at these aspects, a distinctive trend is the use of a shell-and-tube vaporizer (STV) with a closed-loop intermediate fluid and ambient air as the heat source. The intermediate fluid may be a glycol, a glycol-water mixture, methanol, propanol, propane, butane, ammonia or formate. This intermediate fluid vaporizes LNG in the STV, and the cooled intermediate fluid is sent to an ambient air heater (AAH), where it regains the required heat from ambient air and then returns back to the STV, forming a closed loop. FIG. 1 shows a typical process flow diagram for an LNG regasification terminal with an STV with a glycol-water mixture as the intermediate fluid and an AAH as the primary heat source.

Regas vaporizer and heater structure.

In general, an LNG regasification terminal with a capacity of 5 MMtpy that uses an ethylene glycol-water mixture (36 wt%) requires four parallel working units of STVs and AAHs. Each AAH has approximately 24 bays, 48 tube bundles and a design heat duty of 36 MW. A considerably large plot area (around 7,600 m^2) is required for the installation of the AAHs. The number of units can vary, depending on the size of the STV. Using a larger-size STV may require fewer units.

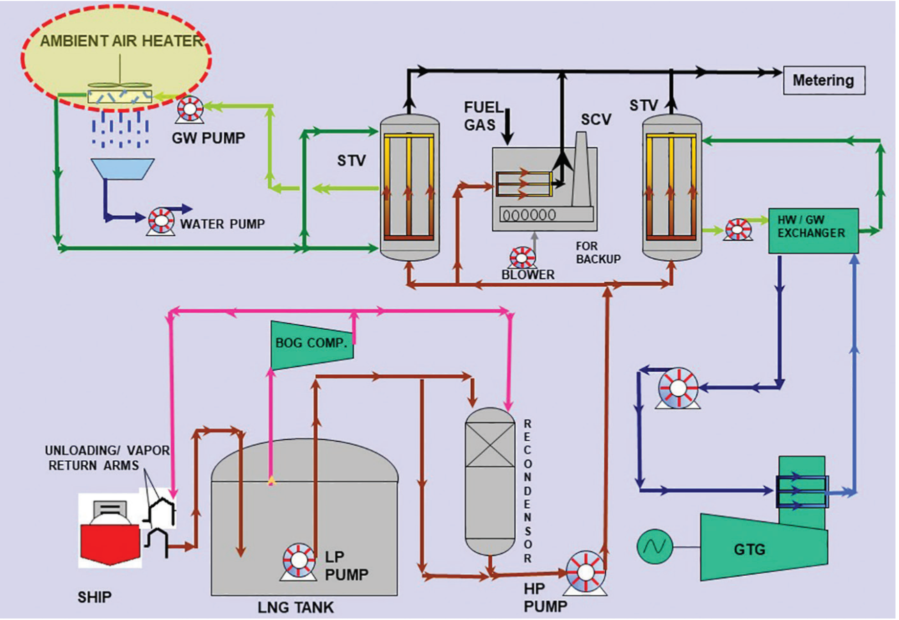

FIG. 1. Typical process flow diagram for an LNG regasification terminal with an STV.

An AAH looks similar to a conventional air-cooled heat exchanger (ACHE), which is widely used in refineries and other industries; however, the purpose of an AAH in LNG regasification terminals is the opposite—i.e., instead of cooling the hot process fluid by atmospheric air, the AAH heats the colder intermediate fluid coming from the STV by using the comparatively hot ambient air. FIG. 2 shows a typical AAH installation in an LNG regasification terminal.

Challenges to heater design.

An AAH presents challenges related to thermal design, construction and operation compared to the conventional ACHE. The following sections discuss those challenges in detail, along with recommended solutions that have been successfully implemented in many LNG regasification terminals.

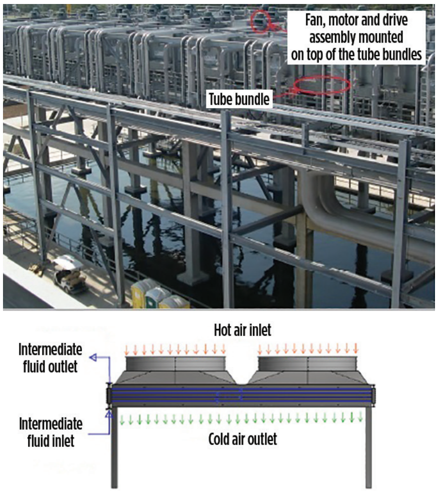

FIG. 2. Typical AAH installation in an LNG regasification terminal.

Temperature and humidity. Atmospheric temperature and relative humid-

ity (RH) at any location fluctuates within a day and throughout the year; they also fluctuate within an LNG regasification terminal. Varying atmospheric temperature and RH influence the performance of an AAH. Therefore, it is crucial for a process engineer to carefully analyze past meteorological site data while determining operating scenarios or cases for designing the AAH. A minimum approach temperature (i.e., the difference between the inlet temperature of ambient air and the outlet temperature of the intermediate fluid) of 3°C–4°C is recommended to achieve an economical and efficient AAH design.

The AAH performs at maximum capacity during higher atmospheric temperatures, and some of the fans forcing air into the AAH may be required to switch off. However, it is recommended to use variable frequency drives for at least 50% of the total number of fans and motors to ensure effective process control and maximum electrical power savings in the AAH.

During lower atmospheric temperatures, water vapor present in ambient air commonly becomes condensed when passing through the tube bundles due to the transfer of heat to the intermediate fluid flowing inside the tube bundles. This condensed water vapor tends to slide down to grade by its gravity.

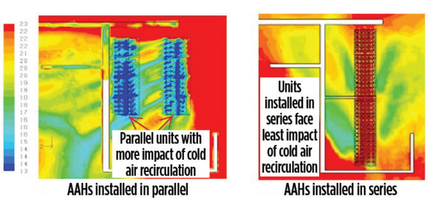

FIG. 3. Parallel installation for the AAH is more susceptible to cold air recirculation than AAH installation in series.

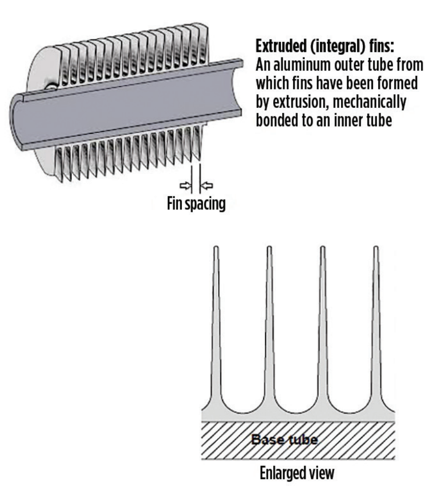

FIG. 4. Recommended minimum fin spacing to enable the release of condensed water from tube and fin surfaces on the AAH.

Condensed water and fan issues. As shown in FIG. 2, it is recommended to force the air into the tube bundles from the top by forced-draft fans and install the complete drive assembly (including fans, motors and a belt drive) at the top of the tube bundles to avoid rust, corrosion and damage. This recommended arrangement also helps minimize departed cold air recirculation, discussed later in this article. It is important to mention that a good amount of condensed water is collected at grade below the AAH, which must be suitably utilized.

While fans are located at the top of the tube bundles and force air from top to bottom, it is recommended to flow the intermediate fluid from bottom to top inside the tube bundles. Therefore, the inlet nozzles for the intermediate fluid should be located at the bottom of the tube bundles and the outlet nozzles should be located at the top of tube bundles, as shown in FIG. 2. This way, a counter-current to crossflow arrangement is achieved between the two fluids, which improves the logarithmic mean temperature difference (LMTD) and the heat transfer coefficient, therefore improving the thermal performance of the AAH.

Due to the condensation of water vapor present in ambient air, substantial fog and mist is generated below the tube bundles and around the AAH. This phenomenon becomes more significant when the unit is operating during lower ambient temperatures, high humidity and low wind conditions.

With the given AAH layout, site meteorological data (e.g., prevailing wind direction and wind velocity) and wind obstructions (e.g., surrounding tall structures, LNG tanks, buildings, etc.), it is recommended to carry out a computational fluid dynamics (CFD) analysis for the AAH to predict air stream behavior. Based on this CFD analysis, a suitable elevation and appropriate layout for the AAH should be selected so that the surrounding hot atmospheric air can mix with the exiting cold air from the AAH to considerably reduce fogging. However, a higher elevation can result in the carryover of condensed water with wind, which must be prevented by a condensed water removal system.

Cold air recirculation. Some amount of cold air exiting the AAH recirculates back to the fan suction at the top of the tube bundle (i.e., cold air recirculation). This further reduces the temperature of air entering the AAH, which can impact the overall performance of the AAH. As previously recommended, a CFD analysis is essential to accurately estimate the occurrence of cold air recirculation and its impact on suction air temperature. Based on the results of this analysis, necessary corrections to the design air temperature or implementation of adequate overdesign margins must be taken into consideration for the design of the AAH.

Detailed investigations that have been carried out at various LNG regasification terminals reveal that cold air recirculation cannot be fully avoided, but its effect can be minimized by selecting a suitable elevation and proper layout for the AAH. As shown in FIG. 3, a parallel installation for the AAH is more susceptible to cold air recirculation than AAH installation in series. This is because cold air recirculation is mainly caused by the confluence of air streams coming from the parallel units. Hence, the simplest and most efficient solution for minimizing cold air recirculation is to install AAHs in series.

Latent heat considerations. The most important aspect in the optimization of the thermal design of AAHs is to consider the latent heat released by the condensed water vapor. The amount of condensed water depends on the site-specific relative humidity and dewpoint temperature. The latent heat of the condensation of water is substantially higher than the heat of air. Considering a higher relative humidity in design, the size and cost of the AAH can be considerably reduced; alternatively, a low relative humidity can increase the size and cost of the AAH. In light of this, a process engineer must carefully determine the design relative humidity prior to planning.

Note: The boundary layer of condensed water vapor that forms on the tube and fin surfaces acts as a resistance to the heat transfer from air to the intermediate fluid, which must be taken into consideration in the thermal design of the AAH.

Fin spacing in tubes. Fin spacing in the finned tubes of the AAH must be suitably selected to enable the easy release of condensed water from the tube and fin

surfaces. Closely spaced fins may create resistance in the release of condensed water and may also lead to the formation of a thick boundary layer on the fin and tube surfaces, creating resistance to heat transfer. As shown in FIG. 4, it is recommended to establish a minimum fin spacing of 2.54 mm for extruded aluminium fins, which enables sound mechanical bonding with base tubes and efficient heat transfer.

A higher number of finned tube rows in the AAH is to be avoided. Four finned tube rows are ideal for the easy release of condensed water in both high-humidity and relatively colder sites. In the case of limited available plot area, one or two additional tube rows can be used, preferably with higher fin spacing or without fins and a higher tube pitch.

Maintenance. Provisions for the maintenance of fans, motors and drive assembly mounted at the top of the tube bundles should be provided.

Support structures. Tube bundles for ambient air heaters are generally installed at an elevation of 10 m–13 m. Since water condensation routinely takes place, a supporting structure of concrete can be used for the AAH, instead of conventional hot-dip galvanized steel. In this case, the shop run-in test at the AAH supplier's factory should be carried out with a dummy supporting structure.

Tube length. A longer tube length, a higher number of tube passes and the maximum utilization of allowable pressure drop are the key factors to achieving an optimized thermal design for an AAH. However, the selection of tube length must be aligned with market availability, the available plot area, the feasibility of finning and transportation limitations (if any).

Takeaway. LNG regasification technology, encompassing an intermediate fluid and ambient air as a primary source of heat, has witnessed several environmental, CAPEX and OPEX benefits compared to other technologies, especially for humid and warm locations. The design and configuration features of AAHs described in this article have already been implemented at various LNG regasification terminals, resulting in economical and optimized selection and trouble-free operation of the AAHs.

Selection of an intermediate fluid, operating cases, design ambient temperature, design relative humidity and dewpoint temperature are critical parameters for the sizing of AAHs. A CFD analysis that considers all consequential site meteorological data (e.g., prevailing wind direction, wind velocity and surrounding tall structures like LNG tanks, buildings) provides an accurate prediction of cold air recirculation. This prediction can be used to determine the necessary correction for design air temperature or adequate overdesign margins, suitable elevation and the most effective layout. An effective layout and suitable elevation also minimize the generation of fog due to condensed water vapor. GP

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Ju`aymah NGL fractionation energy optimization initiatives

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Wasting energy reduces plant profitability and its sustainability footprint. With increasing energy costs and environmental impact, energy efficiency is becoming more important than ever. To be aligned with these requirements, an energy optimization program launched in 2017 as well as several in-house initiatives were implemented to optimize the processes for the reduction of energy consumption.

Three major initiatives implemented at an NGL fractionation plant are outlined here, including steam reserve optimization, Adip propane trim heaters shutdown and an automating LPG dehydration regeneration cycle. Implementing these energy saving initiatives successfully reduced approximately 296 MMBtu/hr of energy, lowered operating cost, improved plant energy intensity key performance indicators (KPIs) (EII) by approximately 8.5%, and increased equipment life and reliability.

The energy intensity index (EII) is an index of energy intensity that compares the consumption of primary energy sources at a plant with benchmarks of a similar complex, measuring energy performance. It is worth highlighting that all of the initiatives were implemented without major process modification or capital expenditures.

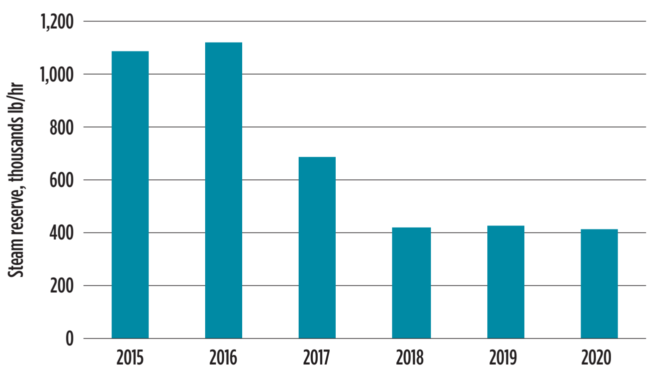

FIG. 1. Steam reserve trend.

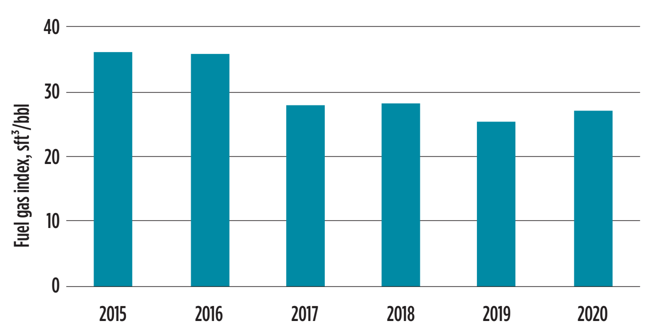

FIG. 2. Fuel gas index trend.

Process background. There are four identical fractionation modules (trains): each module consists of de-ethanizer (De-C_2), depropanizer (De-C_3) and debutanizer (De-C_4) columns; an amine treating facility (Adip unit) to remove hydrogen sulfide (H_2S) and carbonyl sulfide (COS) from C_3 product received from De-C_3 overhead; and mercaptan oxidation (merox) processing units for mercaptan sulfur removal from C_3 and C_4 products, followed by the C_3 and C_4 dehydration system for moisture removal from the final product. A common utility area supplies plant chemicals, boiler feed water and steam. The plant's steam demand is met by three cogeneration units and several high-pressure (HP) boilers. The following sections detail all three energy optimization initiatives.

Steam reserve optimization. The plant's steam demand is met by three cogeneration units and several HP boilers. The total steam demand fluctuates heavily due to significant changes in the feed rate. To meet the steam demand and avoid any adverse operational impact during sudden cogeneration unit or boiler trip, more than the net required number of boilers were always operated. The availability of additional steam production capacity by maintaining the extra number of boilers in operation is defined as steam reserve. Historically, more than 1.1 MMlb/hr (million pounds per hour) of steam reserve was maintained; to maintain a greater steam reserve than net steam demand, additional boilers were forced to operate at a minimum maximum continuous rating (MCR), which is close to 30%. Operating boilers at a minimum MCR is inefficient and results in significant energy wastage.

The objective of this study was to re-evaluate and optimize the steam reserve strategy to improve plant EII and reduce operating costs.

Historically, the steam reserve supported plant operations during cogeneration unit or boiler trips and maintained plant processing capacity. Due to feed fluctuations, cogeneration plant and boilers reliability, associated risks and potential financial losses with no steam reserve, it was concluded that maintaining zero steam reserve is impractical for operation. During any trip of steam-producing facilities, the available steam reserve from the boilers helped maintain plant process-

ing capacity that avoided any large impact on customer supply. It is worth mentioning that it takes approximately 8 hr to start a new boiler should the need arise, while steam production can be ramped up by 10%/min in an operating boiler.

As an alternate approach, standard deviations in the feed fluctuation for the last several years were calculated to estimate steam demand and the steam reserve required to handle feed fluctuations. Sudden cogeneration unit and boiler trips were also considered for establishing a new steam reserve strategy. Analyzing all operating parameters in detail, the plant's team recommended maintaining a steam reserve between 350,000 lb/hr and 650,000 lb/hr (equivalent to one Cogen capacity) to reduce fuel gas consumption, increase financial benefits and improve plant EII KPI.

The recommended steam reserve was sufficient to handle feed fluctuations and plant processing capacity during one cogeneration or boiler trip. Lowering the steam reserve from 1.1 MMlb/hr to the recommended level reduced boiler fuel gas consumption; increased boiler loads close to the MCR limit and enhanced boiler efficiency; eliminated excessive steam venting, which saved both energy and water; and reduced the load on excess steam condensers. The new steam reserve and boiler operation strategy reduced boiler startup/shutdown frequency, which reduced boiler maintenance costs and enhanced boiler life span.

FIGS. 1 and **2** demonstrate the reduction in boiler steam reserve and improvement in plant fuel gas index, respectively. The actual steam reserve reduced from 1.1 MMlb/hr from 2015–2016 to an average of 490,000 lb/hr from 2017–2020. It is worth mentioning that this subject strategy was implemented during the middle of 2017, so from 2018–2020 the average steam reserve was maintained at 423,000 lb/hr. Similarly, due to the reduction in the steam reserve, the fuel gas index reduced from 36 sft^3/bbl (2015–2016 average) to 27 sft^3/bbl (2017–2020 average).

Maintaining steam reserve between 350,000 lb/hr and 650,000 lb/hr resulted in a savings of 242 MMBtu/hr of energy due to the increase in boiler MCR and efficiency. This lowered fuel gas consumption, eliminated steam venting and reduced excess steam condenser load.

Adip propane trim heater shutdown. The purpose of the Adip unit is to remove H_2S and COS contaminants from C_3 hydrocarbon streams produced from the depropanizer column overhead to meet product and environmental performance specifications. The Adip unit must also be operated in such a way as to provide efficient operation of downstream treating units: merox and molecular sieve dryers. The objective of the Adip propane trim heater is to increase propane temperature downstream of the extractor and before the mixer settler configuration in all modules. Using 60-psig steam, the Adip propane trim heater heats C_3 to 135°F to ensure proper ADIP/propane mixing. Mixing ADIP and propane helps to remove any remaining COS from the propane product after the extractor in the mixer settler configuration. An Adip propane process configuration is shown in **FIG. 3.**

An assessment was completed to check if Adip propane trim heaters in all modules can be shut down to save energy without impacting the product sulfur specifications. A field test was

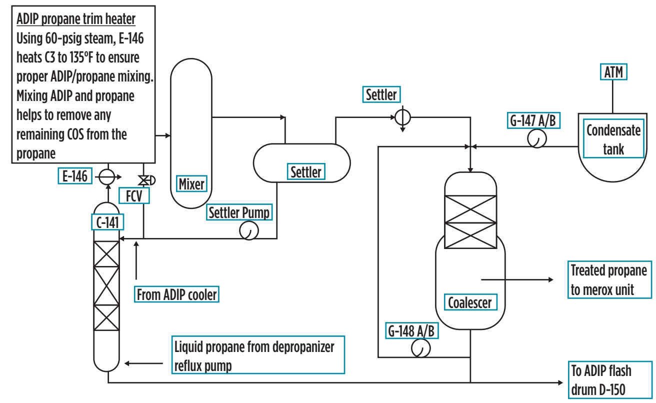

FIG. 3. Adip treating overview.

conducted by bypassing the Adip propane trim heater in Module 1 and 3 for almost 1 yr to span an entire winter and summer. During this shutdown, periodic lab results were analyzed for H_2S and COS removal impact and to determine any impact on the net product sulfur specifications. The long period data analysis revealed no sulfur removal impact due to the subject heater bypass, and total product sulfur, H_2S and COS from the Adip unit during both summer and winter periods remained intact.

Based on the test results, it was decided to shut down and mothball the Adip propane trim heaters in all modules. One reason the product sulfur specification was not impacted as a result of the trim heater bypass was that the plant receives significantly less acid gas (H_2S and COS) along with feed compared with the design value. This was confirmed by comparing the design and actual acid gas loading based on feed composition analysis and the actual acid gas flaring flowrate vs. its design value. Therefore, bypassing the subject heater had no impact on meeting the product sulfur specifications.

Shutting down the propane trim headers resulted in a total steam savings of 50,400 lb/hr of energy, or 45 MMBtu/hr. Additionally, shutting down the subject heaters resulted in a ~1.5 % reduction in the overall plant EII.

LPG dehydration system regeneration cycle automation. During a routine LPG dehydration unit breakthrough test, it was noticed that the fractionation modules dehydrators heating cycle duration was fixed at 11 hr, while the required duration varies depending on the molecular sieves' performance and condition.

As per industry best practices and desiccant supplier/vendor recommendations, regeneration heating should be completed once the temperature difference between the vessel inlet and outlet stabilizes at 27°F–36°F over a period of 45 min–60 min. Therefore, it was recommended to automate the heating cycle duration to be linked with the inlet and outlet temperature differences to achieve the optimum heating cycle duration to avoid overheating the molecular sieves and conserve energy. This brings an estimated steam savings of 9,500 lb/hr, or 9 MMBtu/hr.

Molecular sieve process description. At any given time, one of the dehydrators will be adsorbing water from the feed,

while the other will be in the process of being heated or cooled to regenerate the desiccant online mode. Initially, wet product passes through the operating dehydrator, then is dried and pumped to the refrigeration, storage and/or export areas of the plant, as shown in **FIG. 4.**

The bed is switched to the regeneration cycle after being saturated with water. In this mode, a slipstream of dried product liquid is recycled to regenerate the molecular-sieve beds. The recycled liquid is vaporized with low-pressure stream, superheated to temperatures of 460°F with a high-pressure steam, and then routed to the wet tower to remove the previously adsorbed water.

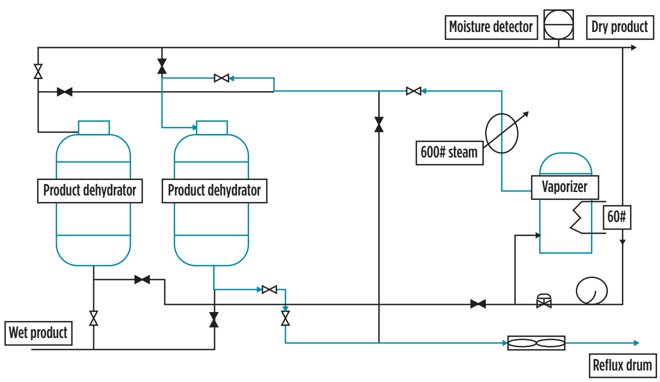

FIG. 4. LPG molecular sieve process.

As the temperature within the tower increases, the water captured within the pores of the desiccant turns to steam and is absorbed by the regenerated gas. This gas leaves the bottom of the tower and is cooled by an air-cooled condenser. When the gas is cooled, the saturation level of the water vapor is lowered significantly and water is condensed. The condensed liquid is recycled to the appropriate upstream reflux drum.

The heating cycle last approximately 11 hr. When the heating cycle is completed and the bed has been dried, a cold recycle liquid is passed in an up-flow arrangement through the tower to return it to normal operating temperatures (about 100°F–120°F) before placing it back into service to dehydrate the wet feed stream. The cooling cycle takes approximately 4 hr.

Breakthrough test results for Modules 1 and 2 showed that the fixed duration of the heating cycle is much higher than required. It was noticed that the required regeneration cycle duration is much less than the existing fixed time where the molecular sieves are exposed to overheating and energy is wasted. The average additional heating time was calculated to be 4 hr.

Therefore, it was decided that the regeneration heating cycle duration for all fractionation modules should be connected to the bed top and bottom temperature difference to optimize the regeneration cycle. As part of this initiative, the regeneration cycle logic was modified and linked with the bed top and bottoms temperature difference. Once the temperature difference reaches 30°F, the heating cycle should be stopped after 45 min. This logic modification was carried out in one of the module's C_3 dehydration systems; after closely monitoring all operating parameters for 6 mos, the same logic modification was implemented in all of the module's C_3 and C_4 dehydration cycles. During the testing period, the bed temperature profile and time interval between consequent absorption cycles were closely monitored to ensure no adverse impact on bed performance due to subject modifications.

Implementing the aforementioned recommendation led to a savings of 9,500 lb/hr of steam, or 9 MMBtu/hr of energy, and enhanced the molecular sieves life by approximately 15%–20% by avoiding unnecessary overheating.

Takeaway. The successful implementation of several in-house energy optimization initiatives resulted in 296 MMBtu/hr of energy savings, reduced plant operating cost, improved EII, and lowered nitrogen oxide (NO_x) and sulfide oxide (SO_x) emissions. These results could not have been achieved without collaborative efforts by operations, engineering and maintenance teams. **GP**

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Turboexpander repair and maintenance for sustained performance and profitability

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Turboexpanders are critical equipment for many applications including gas processing, industrial gas, power recovery and power generation, and their longevity and sustained performance is often key to the profitability of a business. This article provides an overview of the major elements involved in the work of maintaining turboexpanders. The discussion traces issues related to the design and field operation of the machine, as well as shop repairs. Users will find valuable insights and suggestions made by practitioners with an original equipment manufacturer (OEM) and aftermarket perspective.

What is a turboexpander? A turboexpander is a rotating machine equipped with a radial inflow expansion turbine and a loading or breaking device, such as a centrifugal compressor stage, a generator or an oil brake. Unlike a power generation or mechanical drive turbine, which works mainly to generate power, an expander's main purpose is to increase the efficiency of a gas expansion process. FIG. 1 provides a schematic of a typical turboexpander operating in a gas liquification process.[1]

Where are turboexpanders used? More than 5,000 turboexpander units are in operation across the globe in a variety of applications. The equipment is standard in the natural gas industry for liquification and dewpoint control, and it is also commonly employed in the petrochemical industry for ethylene plants, air separation and refrigeration.[1]

In all of these processes, there is a need to change the state of a gas to a given pressure and temperature. For example, a refrigeration cycle requires that the gas be greatly expanded to reduce its temperature. This is referred to as a Joule–Thompson (J–T) effect, which can be accomplished with a throttling valve (gate or otherwise) that achieves a constant enthalpy expansion adiabatically, with no work output.

Turboexpanders can accomplish the same sharp pressure drop more efficiently because the turbine extracts additional work from the gas expansion due to the mechanical motion. In cases in which the loading device is a compressor stage or a generator, the expander provides power recovery.

What are the components of a turboexpander? A typical turboexpander comprises three main sections—namely, the compressor case, the expander case and the mechanical center section (FIG. 2).

Turboexpander cases are usually radially split and grouped in three distinct parts. The expander casing is usually stainless steel, due to the low-temperature gas it contains. In many designs, it houses the inlet guide assembly. The compressor casing is usually made of carbon steel. It forms the diffuser part of the compressor stage, as well as the collector or volute, depending on the design.

FIG. 3 focuses on the mechanical center section (MCS), which is the heart of the machine. The bearing housing is usually carbon steel and contains almost the entire machine, from the expander wheel to the compressor wheel. It includes the rotor, bearings and seals. The following is an overview of the key components of the MCS and their functions and main design features.

Rotor. The rotating element is comprised of a shaft (often made from stainless steel) with a radial inflow turbine wheel attached on one end and the loading device, which in FIG. 3 is a centrifugal compressor wheel, but it could be a generator or a dyno.

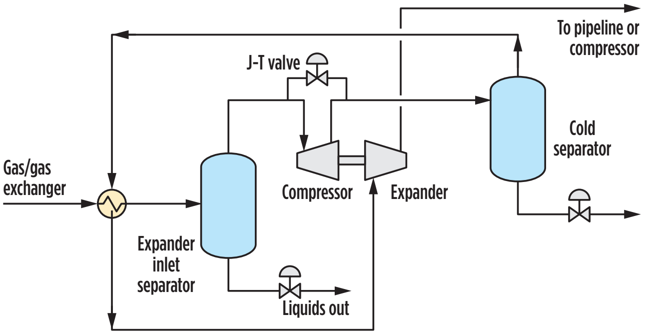

FIG. 1. Typical natural gas liquefaction process.

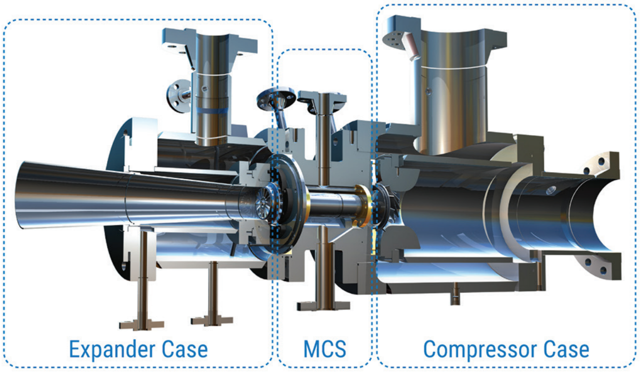

FIG. 2. Turboexpander cross-section. Image courtesy of L.A. Turbine.

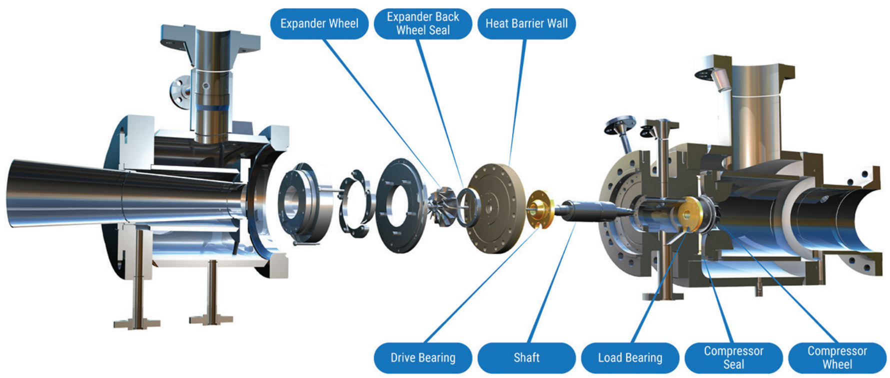

FIG. 3. Mechanical center section detail. Image courtesy of L.A. Turbine.

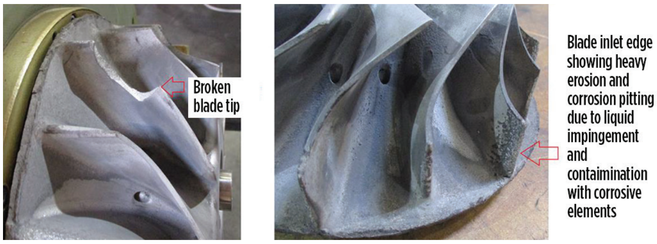

FIG. 4. Wheel with extensive corrosion damage.

Wheels. Wheels are usually computer numerical control (CNC)-milled from a forging, either high-strength aluminum or titanium in some applications. They can be hard anodized or shot peened for additional protection against corrosion.

The wheels can be mounted onto the shaft in a variety of ways, namely, keyed cylindrical or tapered bores, or keyless polygon fits, to name a few. Each wheel can be fastened to the shaft with a high-strength screw bolted onto an internal thread in the shaft. Another common design solution features a hollow shaft with a through-bolt that secures both wheels with end nuts.

The large rotating components are balanced individually first, and later put together as an assembly and balance checked, per the applicable section in API 617. This allows the wheels to be interchanged in the field without having to send the MCS to the shop for a rebalance. However, for some applications, OEMs specify that the rotor be balanced as an assembly and the parts match-marked, in which case the wheels cannot be replaced without a full rotor rebalance.

From a shop inspection perspective, some of the most common findings on wheels include:

1. Wear and/or corrosion to the blade surfaces
2. Dings to the blades due to foreign object damage (FOD)
3. Bent blade tips due to FOD or an error in installation/shipping
4. Excessive rubs in the blade tips due to contact with the stationary surface
5. Rub damage to the labyrinth teeth of a seal that rides in the back of the wheel, if applicable [this seal is called the expander wheel back seal (see **FIG. 3**), and it is intended for control of the thrust produced by the expander wheel]
6. Cracked blades due to mechanical fatigue.

Findings No. 1 through No. 5 are usually repairable depending on the severity of the damage and the judgement of the repair engineer. For instance, FOD on the blades can be dressed and blended by hand. Aluminum alloy wheels can be hard anodized or shot peened to increase resistance to wear, corrosion or cracking.

In the case of finding No. 5, labyrinth seal rub damage on the wheel can sometimes be recovered by mechanically lifting the seal tip in a lathe and re-machining to reclaim design tolerances. The expander wheel back seals are often coated with a soft metal like babbitt, which is abradable. As part of the repair, it is customary to remove the layer of coating, reapply it and re-machine to design specifications. This allows the wheel to be salvaged without compromising its performance. For any of these repair options, the wheel must be rebalanced per OEM specifications.

Cracked wheels are not uncommon, and a root cause failure analysis must be undertaken. Understanding the root cause will help the repair facility formulate applicable remedial measures, such as coatings or full-blown redesigns or material upgrades. A root cause failure analysis also assists the customer to address process issues, like contamination of the process gas with corrosive elements (e.g., hydrogen sulfide), which might not have been part of the initial design intent of the machine.

FIG. 4 shows an example of finding No. 6 in which replacing the wheel was necessary. Here, an expander wheel blade was cracked during operation. A visual examination shows heavy corrosion damage throughout. A metallographic evaluation shows that the crack likely occurred due to a type of mechanical fatigue that is precipitated by a corrosive element (known as stress corrosion cracking). In such an extreme case, some measures can be taken from a repair or redesign perspective to ameliorate the problem. Ultimately, however, resolution of the contamination problem at the plant process level is inescapable.

Bearings. These components support the weight of the rotor, as well as overcome the axial force (thrust) originated by the difference in pressures between the front and back of each wheel. Ideally, the thrust in one wheel would be equal and opposite to that of the opposite wheel, but this is rarely the case. In most cases, turboexpanders are equipped with either hydrodynamic oil bearings (**FIG. 3**) or active magnetic bearings (AMBs) (**FIG. 5**).

Turboexpanders feature compound radial/thrust bearings on each side of the mechanical center section. Oil bearings are commonly of the fixed-geometry type with babbitted tapered-land journal and thrust surfaces. The oil used is typically ISO VG 32, although ISO VG 64 is not uncommon. The taper in the radial and axial surfaces forms a "wedge" of oil between the stationary and moving surfaces, which generates the necessary vertical lift and axial thrust capacity. The oil wedge also provides the needed damping to attenuate vibrations. Some rotor designs are prone to unstable vibrations, in which case tilting pad bearings are used since they provide rotor dynamic stability.

When a turboexpander is sent to a shop for inspection, it is typical to find moderate to heavy wear on the babbitted areas. The wear can be caused by a number of issues, such as oil contamination and/or degradation, excessive rotor thrust, system upsets, etc. From an aftermarket perspective, the scope of repair involves replacement or reapplication of the babbitt layer, depending on lead time and cost. For older designs, this opens an opportunity to consider various design upgrades that make the bearings more reliable.

Sometimes a failure analysis is warranted. For example, FIG. 7 shows a case in which oil contamination led to exceedingly high oil operating temperatures evidenced by bearings covered in black residue (upper image). In another instance, a bearing shows damage to the thrust face caused by electrical sparking during operation (lower image).

Shafts. Shafts are designed to have some protection in the bearing location with chrome plating, high-velocity oxygen fuel (HVOF) tungsten carbide, or even dry film lubricant. These protective measures provide a barrier between the bearing and the shaft base material. Operational problems with the bearings and the seals often lead to some degree of wear or damage in the shaft. The most common is wear or rub damage in the bearing or seal areas. Many times, shafts can be easily repaired by reapplying the coating.

AMBs are common in the petrochemical industry. These bearings require a high-speed, five-axis controller that maintains the rotor in a stable orbit. From a shop repair perspective, AMBs are typically serviced at the bearing OEM due to their complexity. OEMs will perform a thorough mechanical and electrical evaluation and formulate a scope of work.

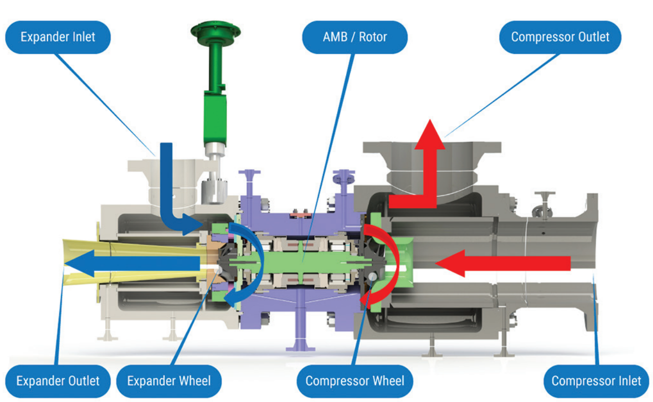

FIG. 5. Turboexpander equipped with active magnetic bearings. Image courtesy of L.A. Turbine.

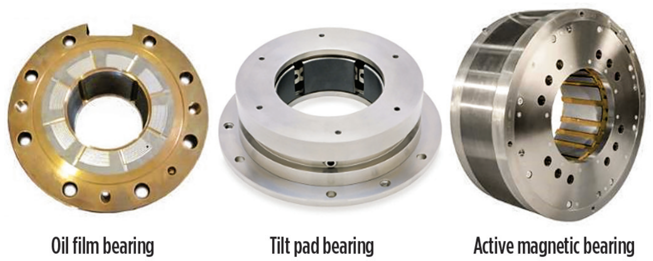

FIG. 6. Bearing options. Images (center and right) courtesy of Waukesha Bearings.

Seals. Shaft seals are placed on both sides of the machine and are typically single-port, non-contacting labyrinth seals. The labyrinth teeth can be located on either the stationary portion of the seal or on the rotating shaft. The seal on the expander end is incorporated into the so-called "heat barrier

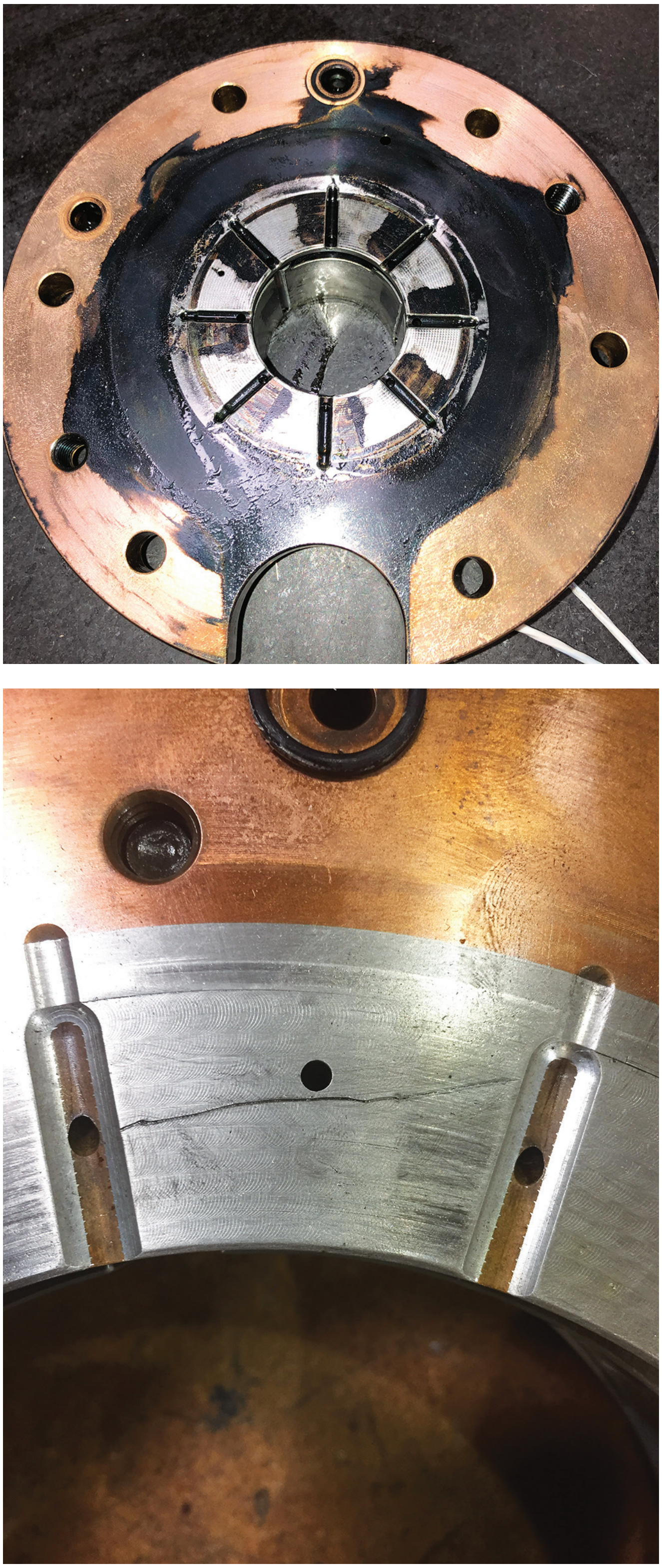

FIG. 7. Oil bearing damage.

wall" (see **FIG. 3** and **FIG. 8**). The heat barrier wall is manufactured from a glass epoxy laminate that provides mechanical strength, as well as insulation of the bearing cavity from the expander section at very low temperatures.

On the compressor side of the machine, the stationary seal element (called a compressor seal, see **FIG. 3**) can be made of different materials, depending on the application, but an aluminum alloy is common. From a repair perspective, a typical finding is that the seal areas—both on the heat barrier wall and the compressor seal—have experienced some degree of wear due to rubs. Rubs are not uncommon and are related to transient excursions of rotor lateral vibrations, usually during startup. They can be repaired by boring out the damaged section(s), installing a blank insert of a matching material and re-machining the seal features to specification.

Inlet guide vanes (IGVs). The inlet guide vanes are the variable stators of the expander stage. The airfoil-shaped mechanical elements provide an efficient aerodynamic flow path for the expander gas to enter the rotating wheel. They also function like a valve, by closing to pinch the flowrate. OEMs differ widely in their chosen designs for IGVs. Some choose to have four or five vanes with simple adjustment mechanisms. Others opt for a larger number of vanes with complex linkage mechanisms.

Parts inside the IGV are exposed to two wear mechanisms: namely, friction and erosion. The friction stems from repeated sliding motion against contacting parts that are pressurized against each other. Erosion wear is fairly common in the surfaces of the nozzle segments in direct contact with the high-speed part-liquid, part-gas flow; therefore, these parts are often designed with hard coatings, such as HVOF tungsten carbide, to provide a smooth, solid surface for friction protection and a hard surface to slow down erosion. Under normal wear conditions, these components can be repaired by removing and reapplying the coating.

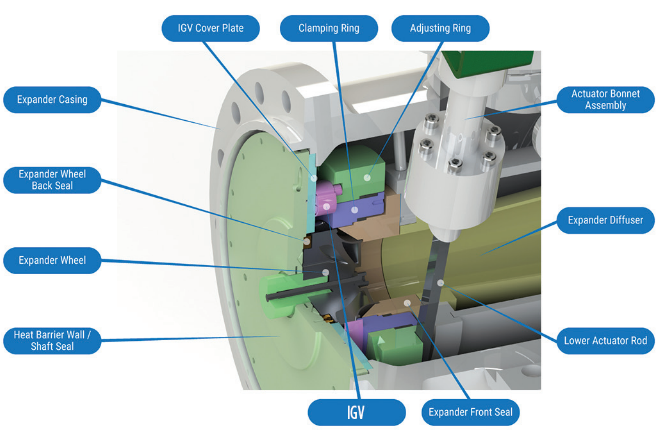

FIG. 8. Variable inlet guide vane assembly. Image courtesy of L.A. Turbine.

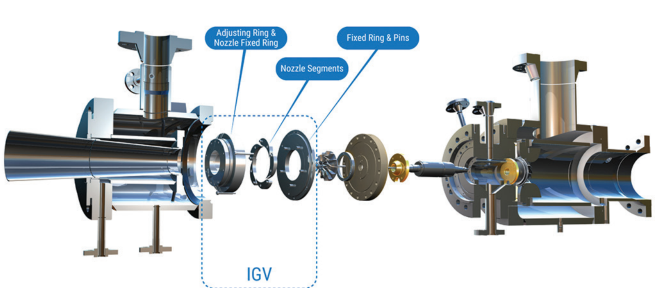

FIG. 9. Inlet guide vane example. Image courtesy of L.A. Turbine.

How should turboexpanders be monitored for health?

A common question among users is how turboexpanders should be monitored for health. Frequent monitoring of the machine after commissioning and during the first year of operation is critical. Operators should keep a log of important data:

- Process temperatures and pressures in the expander and compressor (if available) streams
- Bearing support system—i.e., lube oil system (if it is an oil-bearing machine)
- Rotor vibrations
- Seal gas filters
- Valves.

Such information is instrumental in providing visibility to mechanical problems or performance deficiencies. Data can be retrieved from the human machine interface (HMI) and/or the distributed control system (DCS), or even written down and kept for future reference. While control systems provide warnings and alarms when the expander operates outside of its design constraints, historical data logs may highlight operational changes not easily observed in the HMI. Operations and maintenance personnel should gather a baseline of how the unit performs to more easily identify unfavorable trends over time, and gauge performance after plant shutdowns or upsets. It is important to remember that process drifts and performance deterioration can occur slowly over a period of years and may go unnoticed as the changes turn into norms.

Another common question is whether turboexpanders have an hourly runtime or a periodic overhaul cycle. The answer is neither, as these machines are designed to run practically indefinitely. A turboexpander can be expected to perform as designed for years without issue as long as some operational conditions are met:

- The process remains largely stable and without upsets
- The seal gas and seal gas filters are kept clean
- The lube oil is regularly tested for contaminants and viscosity
- The lube oil filters are kept in good condition or replaced in a timely fashion
- Contamination in the lube oil system or the process is kept to a minimum.

However, if a condition creates the need to increase the level and frequency of preventative maintenance actions, operators should not hesitate to do so. For example, if a plant's process has known contaminates that pass to the expander and cause erosion of the wheel blades, then adding inspections, cleaning and possibly performing changeouts of the expander inlet, along with removing and replacing an MCS at regular intervals, may be necessary. Some issues to consider include frequency of system interruptions, a change in the source for process or seal gas, age of equipment, duration of operation since last inspection and particular application (e.g., natural gas processing, air separation, geothermal power generation).

Several major preventative maintenance inspections should be performed:

1. Lube oil should be checked every 3 mos–6 mos. Oil sampling should be performed to ensure there is no breakdown in the integrity of the lube oil or presence of contaminants that could affect the performance and efficiency of the turboexpander.
2. Routine readings should be documented for operating conditions, processing gases and seal gas to ensure that the turboexpander is operating within engineering design ranges (as previously noted).
3. Critical checks include:
   a. Seal gas differential pressure
   b. Thrust pressure and differential pressure instruments
   c. Lube oil differential pressure (oil-bearing systems)
   d. Lube oil supply and drain temperatures (oil-bearing systems)
   e. Lube oil viscosity (oil-bearing systems)
   f. Lube oil filter differential pressure (oil-bearing systems)
   g. Reservoir oil level (oil-bearing systems)
   h. Auxiliary lube oil pump test (oil-bearing systems)
4. Replace HMI battery every 2 yr
5. Filters should be replaced as they become clogged over time, usually indicated by high differential pressure across the filters.

Even following the best preventative maintenance programs, and often as a result of multiple contributing factors, unscheduled maintenance may eventually be required. **TABLE 1** summarizes typical problem indicators and onsite troubleshooting measures to be performed.

To provide some perspective, the rotating element may spin from 8,000 rpm to 80,000 rpm, and the gaps (or clearances) with the stationary components (bearings, seals and wheels) are often on the order of just a few thousands of an inch. When an issue or upset causes one part to contact another and is damaged, multiple other parts are also affected and become damaged very quickly.

If a problem leads to a shutdown situation, then users can minimize downtime by having a complete spare MCS and complete spare IGV assembly on hand. Swapping the MCS will typically require a downtime of 3 d–5 d, whereas ordering emergency spare parts can take up to several weeks to manufacture and deliver. It is preferable to refrain from swapping out individual MCS or IGV spare parts in the field unless the work can be performed by a qualified technician with proper experience with these machines. Multiple critical clearances, torques, assembly techniques and other standard measurements must be followed with significantly tight tolerances. One missed clearance can easily destroy many major internal parts within seconds.

TABLE 1. Problem indicators and onsite troubleshooting measures for turboexpanders

Issue	Possible causes	Possible solutions
Low seal gas differential	Low supply pressure	Increase setting of supply regulator
	Higher than design expander outlet pressure or wheel pressure	Correct process conditions
	Plugged seal gas filter	Change filter element
	Defective or incorrectly set seal gas differential regulator	Replace or rebuild the differential pressure regulator or adjust setpoint
Low oil pressure differential	Low oil level in reservoir	Fill reservoir as required
	Oil viscosity low	Change oil with new charge and ascertain cause of dilution
	Plugged oil filter	Switch filters or replace with new element
	Oil temperature too high	Investigate malfunctioning oil cooler
	Mechanical damage	Intrusive investigation
High oil temperatures	Oil temperature controller issue	Check oil level and viscosity
	Higher thrust loads	Confirm thrust loads
	High ambient temperature	Confirm that lube oil temperature control valve and oil cooler are working properly
	Fouled air cooler	
Expander will not start	IGVs not fully closed	Set IGVs at 0% closed
	Compressor inlet valve not fully opening	Investigate limit switch or valve malfunction
	Faulty expander trip valve	Investigate valve wiring or solenoid/air supply
	Remote shutdown not cleared	Reset remote shutdown
High thrust differential	Operating outside design conditions	Correct operational parameters
	Faulty/stuck automatic thrust balance (ATB) valve	Overhaul valve and actuator
	Damaged bearings/seals	Intrusive investigation
	Incorrect setpoints	Correct setpoints in HMI

Turboexpander evaluations and repairs. Troubleshooting over the phone or with the help of an onsite field service technician can solve many customer issues. However, in some instances, shop repair may be required. The damaged MCS and/or IGV assembly will need to be shipped to a qualified repair shop with specific experience in turboexpanders.

Repair times vary depending on the severity of the damage. Most turboexpanders are designed for a specific plant's process. Although OEMs have standardized some components, most critical parts are unique to a specific machine, and one OEM's standardization does not correlate to another OEM's standardization initiatives. Rarely does any turboexpander OEM stock parts, even when duplicate units have some standardized parts. Most parts are manufactured to order for each repair. This should be an incentive to operators and maintenance teams to maintain a healthy spares package for turboexpanders.

With the time it takes to inspect and make a proposal, issue a purchase order, repair and manufacture the machine, and assemble and ship the machine, major repairs can take 4 mos–6 mos for oil-bearing machines, and potentially significantly longer for a magnetic-bearing machine.

Upon arrival to the shop for evaluation, the machine will go through a number of general steps before a detailed disposition report can be issued to the customer for consideration:

- Checking for rotor rotation (is the rotor stuck?) and key clearances, such as rotor end play, etc.
- Disassembly and photographic record
- Inventory of parts received
- Visual inspection and recording condition of parts, noting findings of wear, rubs, cracking, corrosion, discoloration, etc.
- Cleaning of parts and photographic record
- Non-destructive examination (NDE) of the wheels and other key components
- Runout inspections on shaft (mechanical and electrical)
- Dimensional record of key components (wheel fits, seal areas and bearings).

Spare parts inventory recommendations. Components are rarely stocked at the OEM. Requested parts are ordered by the OEM from suppliers, or are manufactured to order, usually with long lead times. The following spares are recommended for each turboexpander:

- Major spares include:
  - MCS assembly
  - IGV assembly
- Repair kits and systems spares from vendors include:
  - Accumulator repair kit
  - Lube oil repair kit
  - Regulator differential repair kits
  - Temperature control valve repair kits
  - Pressure transmitter gauge
  - Pressure differential indication transmitter
  - Speed pickup
  - Speed transmitter
  - Resistance temperature detector
  - Vibration probes
  - Vibration transmitters
  - Programmable logic controller (PLC) relay
  - Fuses
- Consumables from vendors include:
  - Filters
    - Lube oil
    - Seal gas
  - Seals
    - O-rings
    - Cup seals (used for low-temperature applications)
    - Gaskets.

A final and important note should be made as to how to store spare parts. For a spare MCS, the wheels should be bubble-wrapped, the ports plugged and the section should be placed in a wooden crate. If an expander has been sitting unprotected for an extended period, as a precautionary measure, it may need to be inspected in a repair shop before the next outage (planned or unplanned). Any corrosion across the expander shaft hub and bearings is a cause for concern, as it could amount to a bearing failure.

The most common method of storage is vacuum packing. After manufacture or repair, the MCS should be placed in a vacuum bag with desiccant, sealed and placed in a wooden crate for long-term storage. This system can provide corrosion protection for approximately 10 yr. After this time, the spare MCS should be inspected by the OEM and resealed.

A costlier, but very effective method of storage is a nitrogen purge container. The container is more robust and is equipped with indicators to show if the purge has been compromised. If the purge is maintained, then there is no end to the shelf life.

IGV assemblies should be crated and placed in a sealed bag with desiccant. Seals, O-rings and gaskets should be kept away from contaminates and in the original packing. The life of Teflon seals and O-rings is usually limited to a 10-yr shelf life from the manufacturer.

Conclusion. Turboexpanders are critical equipment for many applications, and their longevity and sustained performance are often key to the profitability of a business. This article provides an overview of the major elements involved in the work of maintaining turboexpanders. The discussion traces issues related to the design of the machine, field operation and shop repairs. Users will find valuable insights and suggestions by practitioners with an OEM and aftermarket perspective. **GP**

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Realize the full potential of stationary gas engine oil with used oil analysis

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Used oil analysis is widely considered a vital tool for operators of stationary gas engines. While the extent to which different operations are able to commit resources to used oil analysis may vary, many recognize its importance as a maintenance and reliability tool that enables operators to monitor and optimize the life of an engine and its lubricating oil.

Major lubricant manufacturers advise making used oil analysis a central part of a gas engine's maintenance schedule, and most original equipment manufacturers (OEMs) recommend it as part of best maintenance practices. It may also be a condition of maintaining engine warranty, but realizing the full potential of the oil relies on a holistic approach. Used oil analysis does not replace, but rather complements, other recommended practices such as monitoring and trending daily engine oil consumption and performing combustion chamber borescope inspections (**FIG. 1**).

Simply put, used oil analysis involves gathering usable data from the engine's oil and analyzing it to make informed decisions. When carried out correctly, it is a reliable and cost-effective way to extract greater value from a lubricant investment and an effective tool in monitoring the health of both the lubricating oil and a stationary gas engine.

A suite of standardized, industry-accepted test methods are needed to analyze the oil. These test methods allow the engine's overall condition to be trended through wear metal analysis and provide an evaluation of the lubricant's condition.

What can be analyzed? The sheer number of tests that can be carried out on used oil can be overwhelming, especially if maintenance staff are not experienced in used oil analysis. It is important to monitor the physical and chemical properties, contaminants and modes of degradation commonly seen in stationary gas engine oils so that those involved in the process can best understand the condition of equipment.

Most engine OEMs list specific limits on these properties. It is crucial that operators are aware of the OEM limits and proactively compare their data to these limits. To retain a margin of safety, the oil must be replaced to maintain performance levels and engine protection prior to the outer limits being reached. It is advised to trend and forecast the data to proactively plan when the oil needs to be changed, rather than reacting to the limits being surpassed and then planning for a maintenance event.

The most important physical property of a lubricating oil is viscosity—the fluid's thickness or resistance to flow. The oil's viscosity is what primarily provides separation of metal surfaces in relative motion to each other, meaning any significant change could lead to increased wear and compromise protection, potentially leading to engine failure.

Stationary gas engine oils naturally experience eventual chemical degradation over time, from processes such as oxidation or nitration. Oxidation occurs when the lubricating oil is exposed to high temperatures and oxygen and can be accelerated by wear metals that can act like catalysts. Nitration, on the other hand, is caused by the oil's exposure to nitric oxides (NO_X), as found in gas engine exhaust gases. All gas engines will have some level of nitration in the used oil, but it is more pronounced in stoichiometric gas engines, as they produce high levels of NO_X in the exhaust gas (**FIG. 2**).

Both forms of degradation can cause the oil to thicken or produce sludge, varnish and deposits, as well as cause the formation of acids, which can lead to corrosive wear. Oxidation can also form carbon deposits in piston ring grooves and on the backside of piston rings. Nitrated sludge is very difficult to remove from an engine and can send oil service life into a downward spiral. Most engine oil OEMs set limits on oxidation and nitration, so it is important for operators to measure the levels of degradation and replace the oil if it approaches those limits.

Fourier transform infrared spectroscopy (FTIR) is an efficient test method that identifies these forms of degradation, as well as certain contaminants. FTIR compares the spectrum of used oil to that of new fluid. The difference between the used and new fluid spectrums indicate what form of degradation is ongoing and to what degree it has occurred.

Tests also exist to measure the levels of acidity and alkalinity of the oil, both of which can be influenced by oxidation and nitration. Total acid number (TAN) measures the level of corrosive acids that have formed in the oil from oxidation and nitration and is especially required when extending oil drain intervals. TAN

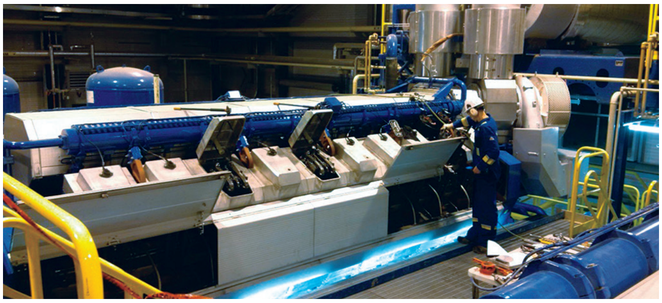

FIG. 1. Technical services advisor performing a critical gas engine borescope inspection.

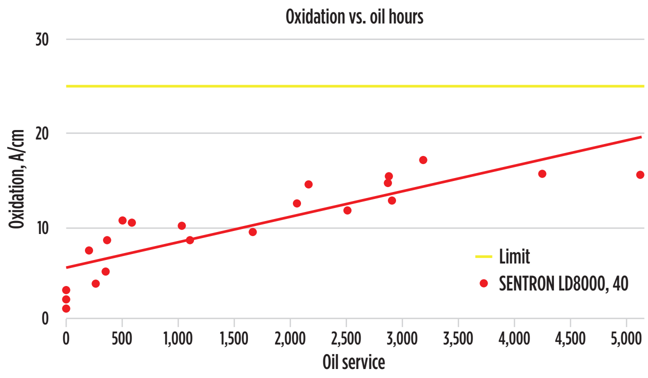

FIG. 2. Oxidation increases with oil service.

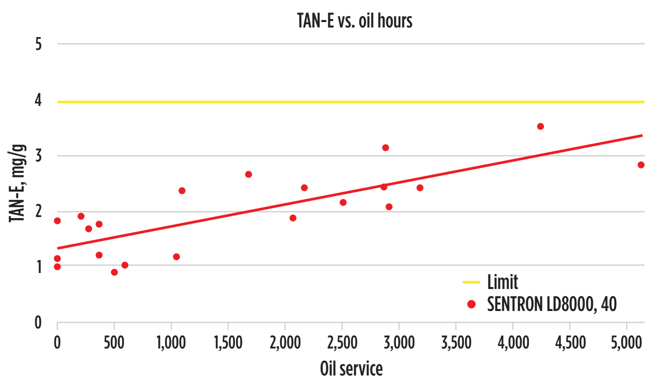

FIG. 3. TAN increases with oil service as a result of fluid oxidation.

values typically start off lower and then gradually increase over the life of the fill as oxidation and nitration occur (**FIG. 3**). The initial pH (ipH) of a fluid complements TAN measurements and can identify the formation and level of strong acids even earlier, which is particularly important in landfill and biogas applications.

Total base number (TBN) measures the fluid's reserve alkalinity. Over-based detergent additives contribute to this alkalinity, and the fluid's TBN value decreases as these detergents neutralize harmful acids. This test is most relevant to diesel engine oils, which have higher amounts of detergents but can, and should, be used in stationary gas engine oils as required by the manufacturer for extended oil drain intervals.

Focusing on proper sampling. Used oil analysis is conducted by most gas engine operators, but some aspects may be overlooked that prevent an operator from realizing the full value of the analysis. For example, a program can be compromised if proper oil sampling techniques are not followed. Several steps should be used to take a representative sample:

- Samples should be taken from the same location and at the same interval.
- The sample valve should be installed after the engine oil pump but before the oil filters.
- Samples should be taken while the engine has been running at normal operating temperatures and load for at least 1 hr.
- The sample valve and related tubing/piping should be purged before filling the oil sample container. The sample container must be kept clean prior to taking samples.

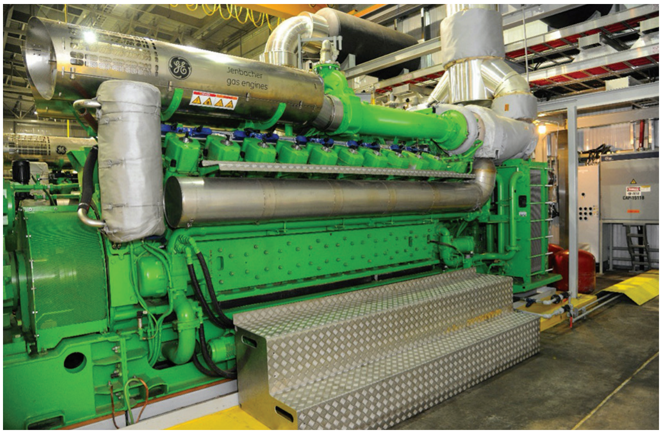

FIG. 4. Large gas engines should be sample monthly at minimum or sooner, depending on the OEM requirement.

- All relevant engine and oil information should be included during sample registration, including the brand name of the oil in use, total engine hours, oil service hours and whether or not the fluid was changed after the sample was taken.
- The sample should be sent to the lab as soon as possible.

After these steps have been taken and the used oil has been sampled, operators should focus on reviewing and trending the data. A new oil reference sample must be listed on the analysis report to compare the properties of the used fluid with those of the new fluid.

The rate at which an engine consumes oil is also an important factor to consider, as higher consumption rates (and subsequent higher fresh oil makeup rates) have a sweetening effect on the fluid's health, whereas an engine with minimal consumption may degrade the oil sooner.

Large gas engines should typically be sampled monthly, but this can vary depending on the manufacturer, so it is important to adhere to the engine OEM sampling frequency (**FIG. 4**). When analysis results indicate the development of an abnormal condition, it is also prudent to re-sample more frequently to closely monitor increased wear rates and fluid degradation.

Realizing the full value. While almost all operators conduct some form of used oil analysis, some use it strictly as a tool to identify mechanical failure. Operations focused on efficiency and best practices also monitor the fluid's physical properties and chemical degradation, contaminants and equipment health in stationary gas engine oils. Gas engines are of significant value, so the investment in monitoring the aforementioned items is simply good business.

By doing this, operators can gain a clearer picture of the oil's condition and overall engine health and realize the true value of used oil analysis. For example, water is a catalyst for oxidation, and the presence of water in an engine increases the rate of corrosive wear and can contribute to hydrolysis. The presence of water in the oil can be screened by the crackle test, but the Karl Fischer test method can more accurately identify how much water is present. Excess water contamination can actually increase the oil's viscosity, but it also reduces the load-carrying capability of the fluid film as it forms an emulsion.

Elemental analysis is also standard testing and uses a method

known as inductive coupled plasma (ICP). ICP identifies and quantifies elements found in additives, contaminants and wear metals. It is important to trend additive elements, such as calcium, zinc, magnesium and phosphorus, as they can help identify a mixture of fluids, and an increase in their concentration can also be indicative of overextended oil drains, oil evaporation loss or high oil consumption rates. Contaminant elements, such as silicon, can be extremely detrimental. For example, in landfill gas applications, silicon enters the engine via fuel gas in the form of organo-silicon compounds. Coolant contamination can be identified by rising levels of sodium and/or potassium.

Wear metals such as iron, copper, tin and lead should also be trended over time to establish what is normal for a particular engine. Where the trend deviates from normal or if wear metal levels exceed the OEM listed limits, further action should be taken. When an increase in wear metal is observed, it is always good to see where oxidation, nitration and TAN are trending as a more degraded fluid can contribute to corrosive wear. Due to particle size detection limits of the ICP test method, oil filter analysis greatly complements wear metal analysis and is recommended as a best practice.

Other elements are likely to be found in a stationary gas engine oil, so it is important for operators to consult their OEM manual and lubricant specialists, both of which can provide advice specific to an operation. If operators can leverage the analysis data as a whole, then it can provide clear insight into the lubricant's condition. This enables operators to make more informed maintenance decisions.

Using the data. Once the data from the used oil analysis is in hand, the next step is to manage and interpret it quickly to enable effective and informed decision-making. Reliability and maintenance teams are increasingly taking advantage of online lab diagnostic tools and customized asset management reporting, which supports efficient and effective data analysis.

Such tools can allow rapid sample registration and sample results to be accessed from tablets or mobile devices, so maintenance and reliability professionals can access the latest insights at any time. Dashboard graphs help prioritize critical results and detect abnormalities within the results—e.g., an increase in wear metals or reduction in fluid viscosity. Utilizing oil diagnostics helps keep an operation one step ahead by using the latest technology to proactively track where maintenance is needed now and predict where it will be needed in the future.

Making informed decisions. A successful used oil analysis program can enable operators to determine the mechanical condition of the engine. The trending and analysis of wear metals allows the identification of problems in their infancy. This is a significant value proposition, as issues can be dealt with before they escalate (**FIG. 5**). For example, it is known that oxidation and nitration are inevitable in stationary gas engines, but by trending the rate of degradation, the oil can be replaced before it becomes too acidic, which could otherwise lead to corrosive wear.

Analysis of used oil data can also provide insight into why problems are occurring in the engine and can provide clues to help pinpoint the source of certain wear and degradation modes. As an example, in lean-burn gas engines, the rate of oxidation is usually at least two times that of nitration (model de-

FIG. 5. Reliable fluid analysis is critical to protecting critical, high-performing engines.

pendent). If the rate of nitration becomes even with or exceeds the rate of oxidation, this can indicate an overly rich air-to-fuel ratio. Digging deeper into this data allows operators to address the causes of certain conditions, as correlations are often present. It can also enable more informed lubricant choices to be made to optimize the operation. Analysis could show that operating conditions are detrimental to the lifecycle of the oil and that a different stationary gas engine oil, specially designed for certain conditions, would be more suitable for the operation.

Carrying out a successful used oil analysis program can put operators in a good position to extend the lifecycle of the oil, but it cannot be the only factor. Physical inspections of mechanical components must supplement used oil analysis, and only then can operators make an informed, holistic decision. That being said, OEMs should be consulted before extending drain intervals, as this can void warranty if not managed correctly. When effectively using all of this data to make informed decisions, operators can also begin to make changes that add to the long-term protection of their equipment.

Used oil analysis may be common practice, but operators can always find additional efficiencies. It is important to know what should be analyzed and why, as well as to possess a deeper understanding of what is causing the results and what that means. Combined with proper oil sampling techniques, this can provide the opportunity to realize the full value of used oil analysis to produce a clear picture of what is happening to the oil and the engine.

This combination enables operations to make proactive, informed decisions to identify issues before they become too expensive to repair and to optimize their operation. Combined with physical inspections and oil consumption rate trending, it provides users the opportunity for efficiencies, improved performance and the ability to get the most out of the oil being used in the engine. **GP**

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Dry gas seal failure analysis and reliability improvement

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Dry gas seals (DGSs) are comprised of many delicate components used for sealing and are used on axial/centrifugal/screw compressors and turboexpanders in various industries. DGS failures are the greatest cause of compressor downtime—in the author's experience, about 48% of compressor failures are due to DGS failure. To avoid this, it is essential to apply the correct DGS for the desired and appropriate function, and to analyze the cause of failure in a systematic way.

However, even if a DGS is selected correctly, it can fail more quickly than anticipated. This article addresses a systematic approach to DGS failure analysis based on the author's experience.

The DGS is a pressure-balanced, gas-lubricated, end face seal in which the sealing mechanism is comprised of two faces: one stationary and the other rotating with the compressor shaft. The stationary seal is called a seal stator, primary ring or spring-loaded face. The rotating face is called a seal rotor, mating ring or seat. The rotating face is etched with grooves partially across the face that, in conjunction with the seal balance, create face separation by both hydrostatic (pressure) and hydrodynamic (shear) forces. Face separation is typically a 3-micron–5-micron (3-µ–5-µ) gap (see **FIG. 1** for a better understanding of the size)[1]; however, depending on the design, service, application, etc., the gap may be changed. Leakage across the faces is a function of pressure differential, temperature, physical properties of the gas, seal size, seal geometry and rotational speed for a given seal design.

American Petroleum Institute (API) 692[2] includes definitions, nomenclatures and detailed information about different types of DGS. API 692 includes four types of DGSs: single-seal, double-seal, tandem-seal and tandem with intermediate labyrinths. Double-seal DSGs are normally used in highly toxic or abrasive process gases or where there is a very low suction pressure. Double-seal DSGs work at low pressures with a nitrogen seal gas supply.

FIG. 2 shows a tandem-seal DSG with intermediate labyrinth configuration with a process side seal and a non-contacting bushing separation seal, which consists of two single seals arranged in series separated by a labyrinth. Tandem-seal DSGs with intermediate labyrinth are suitable for

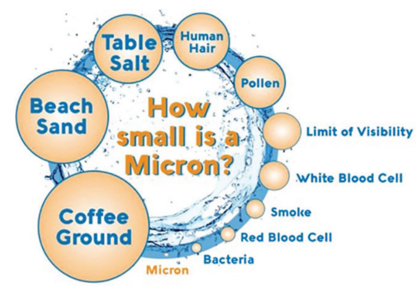

FIG. 1. The size of a micron (µ) compared to bacteria.[1]

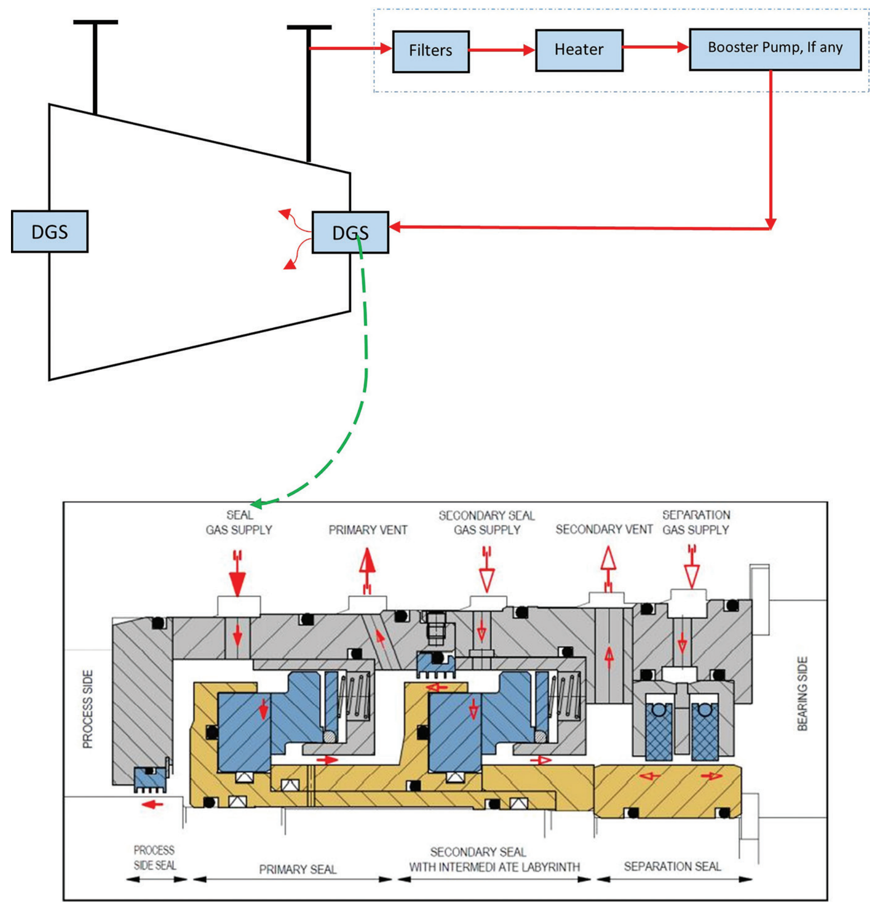

FIG. 2. Tandem seal with intermediate labyrinth schematic, API 692.[2] The blue dashed line is the boundary of the DGS panel.

medium- and high-pressure applications (e.g., > 82 barg) where leakage of process/seal gas to the atmosphere is unacceptable.

Seal gas is injected between the process side seal and the primary seal faces. The majority of the seal gas flows into the compressor and a small amount flows across the primary seal faces. The seal gas pressure is reduced across the primary seal to primary vent pressure. The intermediate labyrinth provides a restriction between the primary and secondary seal. Secondary seal gas is supplied between the intermediate labyrinth and secondary seal to provide a barrier and prevent primary seal leakage from reaching the secondary seal. Leakage from the primary seal is diluted with secondary seal gas and routed to a vent system. Secondary seal leakage is reduced across the secondary seal to atmospheric pressure and typically routed to the atmosphere. In case of primary seal failure, the secondary seal is designed to operate at primary seal conditions, which prevents uncontrolled leakage to the atmosphere and achieves a safe shutdown of the compressor.

Double-seal DSGs are used for highly toxic or abrasive process gases or where there is a very low suction pressure. Normally double-seal DSGs work at low pressures with a nitrogen seal gas supply.

Dry gas seal failure statistics. According to a John Crane webinar training DGS failure course, DGS failure statistics are shown in **FIG. 3,** which indicates:

- 80% of DGS failures are due to significant contamination
- 50% by hydrocarbon (either liquid from the process gas or lube oil from the bearing housings)
- 10% of failure related to solid/particulates contamination due to dirty pipework, incorrect or poor filtration of the primary, or secondary gases supply to the faces
- 4% by chloride content of the process gas
- 2% due to free water from the process gas
- 14% due to unknown contaminations.

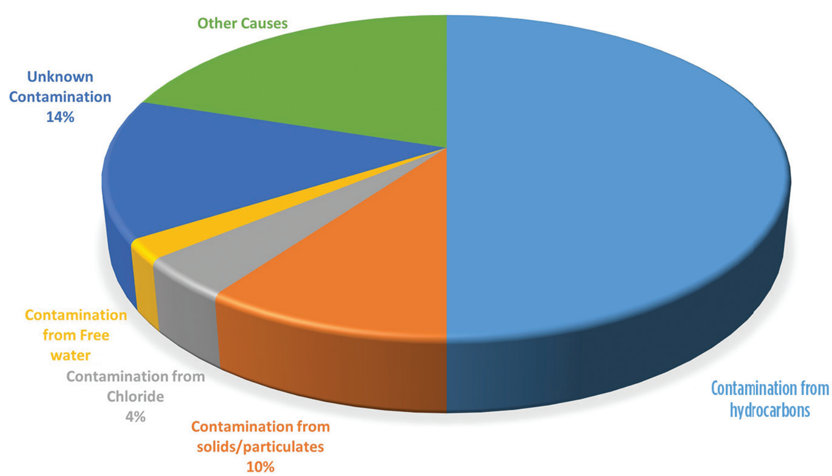

FIG. 3. DGS failure statistics. Source: John Crane webinar training course, July 2020.

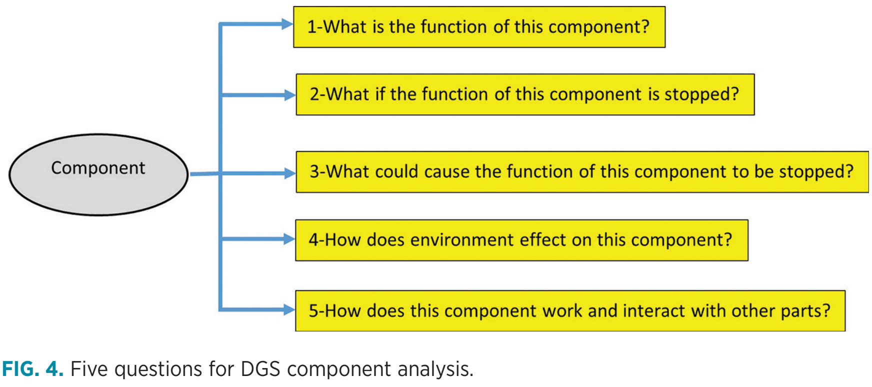

FIG. 4. Five questions for DGS component analysis.

Data collection. In any root cause analysis, data collection is vital. An effective root cause analysis cannot be conducted without searching, interviewing, going to the site, conferring with various departments, etc. Reliability engineers should be aware that the opportunity for data collection will be lost when the DGS is removed from the compressor, so data collection must begin as soon as a work order is generated. Reliability engineers should collect the full details of "actual" operating data at the time of failure. The following information should be collected:

- Start/stop condition and history
- Vibration trend of the machine
- Cartridge pressure test
- Cold standby duration
- Hot standby duration
- Dynamic failure (i.e., failure below the 1-hr initial running time)
- Operating hour
- Sudden failure or progressive leakage increase
- Alarm/shutdown setting
- Any Management of Change (MoC)
- Storage time
- Any change in operational condition
- Dimensional checking and change
- DE/NDE condition
- Any unusual condition
- Any deviation from normal procedure.

Dry gas seal components analysis. The causes of DGS failure are identified to help reliability and maintenance teams mitigate and avoid future failures. Although wear is a potential cause, the author's industry experience indicates that this is only the case in ~10% of mechanical seal failures.

To correctly determine the root cause of a mechanical seal failure, reliability engineers should utilize evidence to form an accurate seal failure analysis. **FIG. 4** includes some questions that should be asked when reviewing a mechanical seal failure.

Contamination by process gas. FIGS. 5 and **6** illustrate ways in which the DGS cartridge can be contaminated by process gas, particles or liquid. If it is assumed that the compressor gas is clean, the question may arise as to why the primary seal gas supply is necessary. The compressor gas can leak from the inter-stage labyrinth toward the DGS. Can that leaked gas be used instead of the primary seal gas, and why is spending required for a dry gas seal condition skid?

The answer is that the gap between the primary ring and the mating ring is about 3 μ (the size of bacteria), so the gas must be filtered to maintain the gap without damaging the surfaces. The gas inside the compressor is too dirty to be used directly into the seals, as this gas comes from carbon steel piping and vessels. The control and monitoring system is designed to provide a positive differential pressure so that filtered gas can prevent a migration into the seal directly.

The DGS is a non-contact seal, meaning that the faces are separated by a gas film of 3 μ–5 μ when the compressor is running and before startup. To lift the faces, a seal gas supply of minimum 5 barg–6 barg pressure is continuously and steadily injected between the faces. This depends on a number of factors, such as curvature, groove depths, size, etc. Sometimes this value may be lower.

However, when the compressor is unpressurized and in cold standby condition, the faces are in contact. If the compressor is shutdown under gas pressure, a "settle-out pressure" will still be applied to the inboard seal. This will provide lift and a gap preventing face contact. Normally, settle-out pressure is higher than the minimum lift up pressure, but the seal can still operate if it is equal.

In a hot static condition, the temperature must not decrease to an unacceptable level where liquids will drop out of the gas, causing problems and damage. If an intermediate labyrinth and secondary seal gas are used, this will provide lift and a gap to the outboard stage. If no pressure is acting on either sealing stage, the seal will be closed with no gap. Prior to restart, pressure must be applied to the seal to prevent the sealing surfaces from rubbing against each other.

During compressor shaft alignment with the gearbox shaft or driver shaft using dial gauges or laser alignment devices, the shafts can be rotated when the seals are unpressurized. The shaft must be rotated in the correct direction; this will not damage the sealing surfaces. The shaft will rotate statically with no pressure acting on the seals. Normally, a device is supplied to manually rotate the shaft—this is possible even on large-diameter shafts. It is highly recommended to clarify with the DGS manufacturer and follow the DGS's operating manual. The author has experienced no damage to the face surfaces when the compressor shaft is hand-rotated with no pressure.

Case study: Contamination with lube oil. During commissioning of a centrifugal gas compressor, the oil pump started flushing oil, bypassing the permissive signal and without any separation gas due to a lack of utility. The DGS cartridges were heavily contaminated with lube oil. During operation, an engineer noticed errors made by the contractor and realized it was fortunate the compressor did not start.

When liquids form between the seal faces or oil reaches the faces while the compressor is not rotating, they may stick together. The flat surfaces of the stationary face and the rotating seat are within two light bands of flatness. With such flat surfaces, the liquid will create a bond between the stationary face and the rotating seat. This is beneficial as it will reduce or even eliminate the seal leakage. Conversely, the strength of the bond is so great that when rotational force is applied to the seat, it will damage the drive pins and the stationary seat. This causes high seal leakage during compressor start or restart and identifies a seal failure and replacement requirement.

If liquids enter the gap between the rotating seat and stationary face, high shearing forces are created that generate high heat. The generated heat leads to gap instability, causing contact between the rotating seat and stationary face, damaging the seal faces and resulting in seal failure. If a failure does not occur during operation with the liquid contamination, the seal will fail at the next subsequent start due to increased shear forces. In a wet mechanical seal, oil film will lubricate and cool the faces; however, with a DGS, the oil film will damage the faces and generate high heat. The oil will burn and create a massive amount of heat, resulting in a fracture of the mating rings.

In this case, all components and parts of the contaminated DGS cartridges were

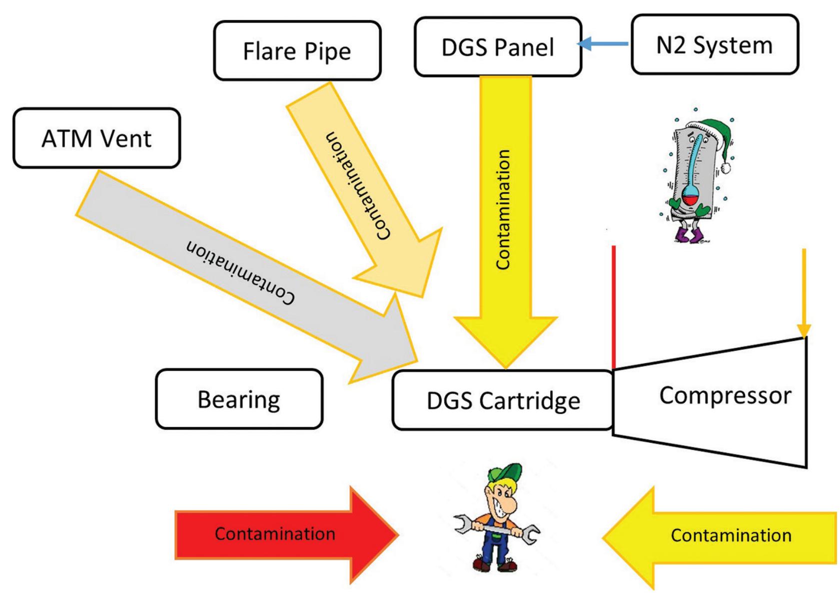

FIG. 5. DGS contamination (process gas, liquid and particles).

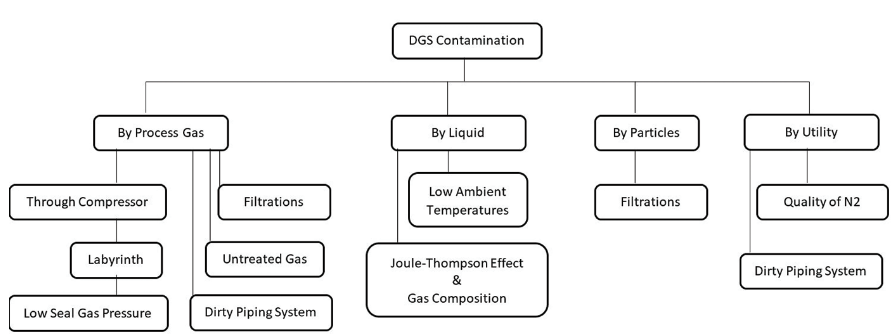

FIG. 6. Main causes of DGS contamination.

removed from the compressor casing, disassembled, cleaned carefully and then reassembled and reused without any problem. It was unnecessary to send the cartridges back to the vendor for cleaning, inspection, balancing, assembly and testing. The case would be different if the compressor was started with contaminated DGSs. In that case, the cartridges should be sent to the vendor, as they would be damaged after compressor startup due to high shear and massive heat generated due to the lube oil.

Causes of mating rings contact. There are two main causes of mating rings contact: no lift and forced contact. Lifting the mating rings requires minimum gas pressure between the faces and minimum shaft speed. Leakage in static and dynamic conditions may occur.

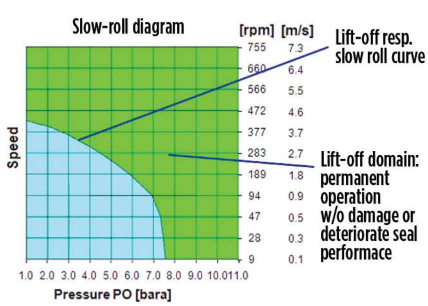

FIG. 7. Typical slow roll diagram (DGS).

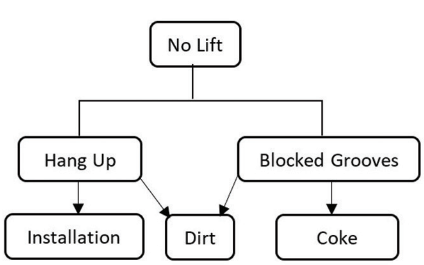

FIG. 8. Causes of no lift.

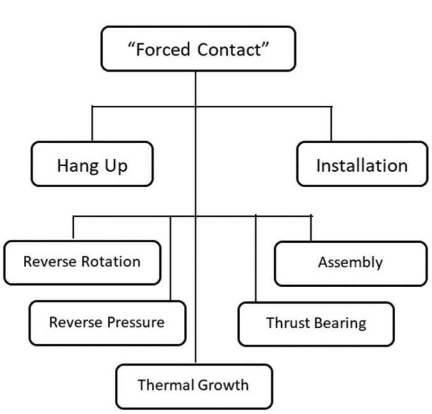

FIG. 9. Causes of forced contact.

The lift of speed is different between unidirectional (2.3 m/sec) and bidirectional (3.5 m/sec) DGSs. In static conditions, such as settle-out condition, slow-run and shutdown conditions, lift off between the rotary/mating face and stationary face is provided by gas pressure only. In dynamic condition, the seal requires less pressure because the shaft rotation sucks the gas into the grooves and generates a high-pressure area between the faces.

During the design stage, the minimum speed for the faces to lift off is calculated based on compressor operating conditons by the seal manufactuerer. This calculation ensures that lift off hapens before/at reaching slow roll speeds. **FIG. 7** shows a slow roll diagram of the DGS based on gas pressure and speed.

Forced contact is where two faces have been forced to contact each other during normal or transient conditions (e.g., startup or shutdown). The result can be three types of contacts:

- Outer diameter contact of the mating rings: In this case, the lift-up may be loosened due to the high risk of groove damage in the rotating ring.
- Inner diameter contact of the mating rings: In this case, the lift-up may be possible due to a lowered risk of grove damage in the rotating ring.
- Full face contact of the mating rings: In this case, the lift-up may be loosened due to the high risk of groove damage in the rotating ring.

FIG. 8 shows some causes of the no lift, and **FIG. 9** shows some causes of forced contact.

Recommendations. The following considerations improve DGS reliability and prevent failure.

Slow run. If the compressor train requires a slow run to complete a cooling or warming cycle—mainly steam or gas turbines as per driver/compressor manufacturer requirements—the specific requirements should be communicated to the DGS vendor. A slow run normally takes 24 hr–36 hr with a speed lower than the lift off speed of the DGS and a lower discharge pressure, which impacts the primary gas seal pressure of the DGS. The seal may require special modifications on the grooves or engineered seal. In this case, temporarily disconnecting the compressor from rotation at low speed may be a solution with the help of a clutch mechanism, as a slow run is mainly required for steam and gas turbines.

Seal gas analysis. Regular seal gas analyses are highly recommended as part of a preventive maintenance plan, preferably on a monthly basis. A provision for sampling from the gas is highly recommended.

Trend analysis. Monitoring seal leakage, flowrates and vent pressure is very important. Out-of-specification leakage and flowrates are indicators of a faulty seal. Other observations of bearing vibration and abnormal temperatures are important indicators of DGS condition.

Oil atmospheric drain. Adding an oil atmospheric drain to the DGS cartridge will help notify the operator if the oil has migrated from the bearing housing to the dry gas seal. Monitoring the trend of separation gas pressures and flowrates are also kety indicators if oil has been leaked to the DGS.

Choose the correct seal faces material. When the rotary and stationary seal faces touch due to a lack of gas pressure or enough shaft speeds, a rubbing and frictional contact simultaneously generates high heat. Selecting the correct seal rings ensures reliability—the seal rings must be hard, rigid, chemically resistant, thermally conductive, tough and wear resistant. Tungsten carbide is a popular seal ring material, and is made by heating tungsten carbide powder and a metallic binder (i.e., cobalt and nickel) to 1,500°C to melt and fuse the binder. Check the chemical compatibility of nickel and cobalt when using tungsten carbide in a DGS. Strong acids can attack binders, causing cobalt formation at the seal faces and premature seal failure. Use proper seal gas with the gas conditioning unit and change the seal material to silicon carbide if a risk of cobalt formation exists between the seal faces.

Shaft lifting. During installation or removal of the DGS cartridges, it is necessary to lift the compressor shaft a few times. This may damage the DGS. Review the procedures and tools with the compressor and DGS manufacturers. Minimize the shaft lifting during installation/removal of the DGS cartridge by using specially engineered components and parts. For example, check if split metallic rings might work instead of solid rings to fix the cartridges to the casing.

Filter cleaning. Do not clean the filter elements in a DGS panel with solvent

or air, and reuse them (when possible) to save money. Always follow the OEM's recommendation.

API 692. Ask the vendor to follow API 692. While API 614[3] contains 35 pages of information regarding DGS systems, API 692 has almost 100 pages in four parts. Part 3 was written to specifically address design issues related to a DGS support system and includes predefined P&ID modules to build systems to suit the application. Annex D of API 692 provides criteria for the selection of different types of DGSs. This standard is becoming more popular with new projects compared to API 614.

System cleanliness. Check the cleanness of all components within the DGS panel, including piping material. It is recommended to use stainless-steel piping to connect the panel to upstream and downstream systems (flare, vent, compressor discharge pipe, etc.) whenever possible. Check internal surface cleanliness of the piping and gas channels in compressor end walls with a professional borescope and perform chemical cleaning where needed.[4]

Risk of condensation. Check and monitor the risk of condensation during all operating conditions, especially standby conditions under settle-out pressure. To avoid condensation, a gas conditioning unit with a gas heater should be used to keep the gas temperature above the dewpoint in all conditions. Considering low ambient temperatures, the need for winterization with electrical heat tracing should be studied. A provision for using warm nitrogen may be required, as well. Consult with the seal vendor as to whether a double-seal DGS has an advantage compared to a tandem-seal DGS to mitigate the risk of condensation. Double-seal DGSs use nitrogen as seal gas, so the gas temperature may not an issue. The use of a coalescing filter will help to separate liquid from the gas; however, liquid can be dropped out after passing the gas inside the cartridge from the intermediate labyrinth or between seal faces due to the Joule-Thomson effect.

Restriction orifices. The primary gas vents contain orifices that keep the gas film between the faces. Ensure that they are installed before the initial compressor startup or after turnaround. Without those orifices, the primary seal will fail. The location and elevation of those orifices are important compared to the compressor shaft center.[4] **GP**

NOTE

The recommendations outlined in this article are based on the author's experience and are not related to any company.

LITERATURE CITED

Complete literature cited available online at www.HydrocarbonProcessing.com.

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Wison delivers first batch of Arctic LNG 2 modules

Wison Offshore & Marine Co. Ltd. announced that four modules for the first train of the Arctic LNG 2 project, weighing nearly 50,000 tons, have been completed after nearly 2 yr of effort and are ready for shipment. The first two modules of the ship officially set sail at WOM's Zhoushan yard today and will be shipped to Russia. The other two modules will be shipped in mid-September.

Developed by Novatek, Russia's largest independent natural gas producer, the Arctic LNG 2 project is the world's largest polar LNG plant. The project consists of three LNG production trains, each with an annual production capacity of 6.6 MMt. For the three trains, Wison undertakes the construction and commissioning of about 150,000 tons of pipe rack modules, including the design, procurement, construction, commissioning and loading of 21 BLM modules. Modules for the first train were delivered from Zhoushan yard recently.

Baker Hughes invests in biomethanation technology

Baker Hughes recently invested in Electrochaea, a growth-stage company developing proprietary bio-methanation technology. Through its investment, Baker Hughes will enhance its broader carbon capture and utilization (CCU) portfolio and provide an integrated solution for customers across the CO_2 value chain to enable the production of low-carbon synthetic natural gas (SNG) from captured CO_2 and green H_2, helping meet demand for cleaner fuels to advance the energy transition.

Electrochaea's biomethanation process is an accessible, highly-efficient, scalable and complementary technology to the Baker Hughes CCU portfolio. The two companies will join efforts to accelerate the scale-up and industrialization of the technology, and they will develop the commercialization of an innovative integrated CCU solution. Once commercialized, the solution will provide to customers a unique ability to transform CO_2 emissions into clean SNG.

Baker Hughes will draw from its portfolio of carbon capture technologies, including its Compact Carbon Capture design, to provide integrated solutions tailored to specific applications utilizing both CO_2 sources with biogenic origin, such as biomass and waste-to-energy plants, as well as sources based on combustion of fossil fuels, such as industrial plants.

SNG is methane that originates from a synthesis process that starts from carbon and hydrogen feedstock. Compared to renewable natural gas (RNG) and biomethane—which have biological origin—or fossil based natural gas, SNG reutilizes CO_2 that would be otherwise emitted into the atmosphere, thereby contributing to significantly mitigating greenhouse gas emissions.

Electrochaea's technology produces SNG from green hydrogen and CO_2 that can come from a variety of sources, such as biogas, fermentation offgas or captured from single-point emitters such as power and industrial plants. SNG can be used for low-carbon heating, transport and industrial applications. In addition, once SNG is injected into existing natural gas pipelines, it can be used as a form of energy storage.

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